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ORIGINAL

Jana Van Ness  
Manager  
Regulatory Compliance

Tel 602/250-2310  
Fax 602/250-3003  
e-mail: [Jana.VanNess@aps.com](mailto:Jana.VanNess@aps.com)  
<http://www.apsc.com>

Mail Station 9908  
P.O. Box 53999  
Phoenix, AZ 85072-3999

Arizona Corporation Commission

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RE: ARIZONA PUBLIC SERVICE COMPANY'S REPORT ON THE ENVIRONMENTAL EFFECTS OF  
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Dear Sir or Madam:

Pursuant to the Decision No. 65743 dated March 14, 2003, Arizona Public Service Company ("APS") is submitting their report on the Environmental Effects of the Track B Solicitation Process.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Jana Van Ness  
Manager  
Regulatory Compliance

Attachment

JVN/vld

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**ARIZONA PUBLIC SERVICE COMPANY'S REPORT ON  
THE ENVIRONMENTAL EFFECTS OF THE TRACK B  
SOLICITATION PROCESS**

**August 12, 2003**

## **I. Introduction**

As part of its March 14, 2003 order regarding the implementation of Track B, the Arizona Corporation Commission ("ACC") required Arizona Public Service ("APS") and Tucson Electric Power to evaluate environmental effects resulting from the Track B process:

Therefore, we will require the utilities to prepare an environmental analysis for this Commission and submit it to this docket within 90 days of the completion of the solicitation. That analysis will detail the environmental effects of the utilities' power supply portfolio resulting from this solicitation against a benchmark analysis of the environmental impacts of the utilities' past five years of operations. Decision No. 65743 at 73.

APS has focused this report on a two-pronged environmental analysis. The first prong is a quantitative analysis of air emissions and water consumption, as measured by emission rates (air) and consumption rates (water). The second prong is a qualitative analysis of demographics, as used in the Track B competitive solicitation process.

For purpose of this analysis only potable water consumption, e.g. surface water and/or groundwater, was considered. Treated effluent used at the APS Palo Verde Nuclear Generating Station and the Pinnacle West Energy Corporation (PWEC) Redhawk Power Plant is not potable water and therefore does not represent a consumptive use of water.

APS notes that the comparative environmental statistics noted in the report are stated in rates of air emissions and water use. This was consistent with the directive of the Track B

Order at page 75. However, the measurement of "rates" is not a measure of total environmental effects. The science of studying environmental effects requires the evaluation of those effects with respect to a receptor (a person or thing) and the method of contact of that receptor with the pollutant (inhalation, ingestion, or dermal contact). Such studies are further complicated by factors such as the cumulative effect of multiple sources of emissions in a given geographical area and different threshold sensitivities of pollutants and receptors. The scientific study of receptors and receptor epidemiology is very time-consuming and well beyond the scope of this analysis. For purposes of this report, APS believes that emission/consumption rates represented a relevant indication of such total effects when coupled with basic demographic data.

While conducting the evaluation, it became apparent to APS that late-2001, 2002 and 2003 were important years in defining the regional profile of new generation available for purchase. These years marked the introduction of significant quantities of power generated from newly constructed natural gas-fired power plants. To account for the changing regional power profile, the quantitative portion of the evaluation was expanded to include three components: an historical benchmark for the years 1998 through 2002; an evaluation of APS' 2003 generation portfolio including the Track B contracts (Scenario 1); and an evaluation of APS' likely 2003 generation portfolio absent the Track B contracts (Scenario 2).

Some of these changes in regional energy mix had, by 2002, already become evident as documented by our evaluation of 2002 data. For this reason, we also highlight the 2002 results separately from the balance of the benchmark period.

Construction of new generation capacity in the region also highlights another key element not captured by the evaluation of environmental measures -- regional increases in generation capacity are the result of increasing market demands for energy in the region rather than economic obsolescence of existing generation. Therefore, the addition of new capacity is not expected to displace existing generation capacity in the APS portfolio except on an energy dispatch basis. The newly constructed natural gas-fired power plants offer increased efficiency with respect to air emissions and often more efficient water consumption when compared to older combined-cycle plants and simple-cycle gas plants. This has been generally true of any new generating facilities throughout the history of this industry. Based on this information alone, one could conclude that the addition of new natural gas-fired power plants to a generation profile would produce the net benefit of reducing air emission rates and potentially water consumption rates regardless of procurement protocols, including Track B.

APS dispatches its system in a manner designed to provide both reliable and economical power. This requires diversity of fuel types and technologies. In a rapidly growing market such as Arizona, APS must rely on all of its generation and purchased power to meet these goals. The purchased power component of APS' portfolio does not displace APS generation capacity. To do so would have a negative effect on both reliability and economics. This is true because potential efficiency benefits of an alternative generation source may be overridden by the specific reliability needs of the APS system or by the higher costs associated with obtaining the potential gain in generation efficiency. Purchase power certainly adds generating capacity value to APS' existing plant portfolio

and will displace existing plant energy dispatch when economical to do so, but will not displace existing plant capacity value. In fact, the results of Track B left APS short of needed generation after 2003 to provide reliable service.

## II. Approach

To accomplish the required evaluation, APS used the criteria in the matrix developed to evaluate the potential environmental effects from the bidders in the Track B process. Specifically, the information submitted with the Track B bids consisted of (i) air emission data expressed as pounds of pollutant per megawatt-hour (lbs/MWh) for carbon dioxide (CO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), particulate matter (PM<sub>10</sub>), carbon monoxide (CO), volatile organic compounds (VOC), and mercury (Hg); (ii) water consumption rates expressed as gallons per megawatt-hour (gal/MWh); and (iii) population within 50 miles of the generating facilities.

For the analysis APS presents the benchmark (1998 – 2002) and the following two scenarios. The benchmark and each scenario considered only the power necessary to serve APS' native load and did not include purchases or generation beyond that required to this serve load.

*Benchmark:* This analysis includes air emission and water-use data for the past five complete calendar years of APS operations (1998 through 2002), which includes APS-owned generation, long-term "fixed" purchase power contracts and market purchased power.

*Scenario 1: Year 2003 Analysis Utilizing Track B Contracts:* This analysis includes APS-owned generation; long-term "fixed" purchase power contracts,

estimated Track B contract power and projected additional market purchased power.

*Scenario 2: Year 2003 Baseline Analysis Absent Track B Contracts.* This analysis includes APS-owned generation, long-term "fixed" purchase power contracts and projected APS market purchased power that would have been provided in the absence of the formal Track B process.

To evaluate the qualitative environmental criteria, APS utilized the available information on demographics provided by the bidders on the recent Track B bid process. Additional environmental information were submitted as part of the Track B bid process, but these data were not considered germane to this evaluation. Environmental information submitted by the Track B bidders is included as Attachment 1. Information submitted by the Track B bidders relating to environmental performance was not verified by APS and often was based on estimates, not actual operating experience.

#### A. Air /Water Analysis

To effectively compile and compare the quantitative environmental data, air emissions and potable water consumption data were grouped by generation source category and then by generation unit type. Air emissions data is reported as pounds of pollutant per megawatt hour (lbs/MWh) and water data is reported as gallons of water (surface water or groundwater) per MWh (gal/MWh). Effluent was not treated as surface or groundwater in the analysis.

Where specific data on air emission or water consumption was not available for a generation source, an emission/consumption rate was estimated as detailed under each of the specific scenarios below. Under each scenario, air emission and water consumption were first totaled across generation source category to create an emission/consumption rate for that category and then across all categories within the scenario.

Benchmark: 1998 through 2002

The APS energy profile for this period of time was divided into three general source categories: APS-owned generation, fixed contract purchases and market purchased power. Details of the values used to compile this profile are provided in Attachments 2 and 3.

APS-owned generation was divided into five unit-type categories: steam, combustion turbine, combined cycle, coal and nuclear. Several APS facilities employ generation equipment under more than one unit type category, while other facilities employ multiple units with divided ownership. Water consumption has not been historically monitored on a unit-by-unit basis, but rather more typically on a plant-wide basis. To facilitate this evaluation, best engineering estimates have been employed to determine individual unit water consumption rates.

Once attributed to individual units, generation in MWh and water consumption (gal)/air emissions (lbs) were totaled across unit types allowing for the calculation of an

emission/consumption rate for each unit type for each year. Emission/ consumption rates for each year of the benchmark were calculated by totaling generation and emission/consumption for all unit types for each year. This number is used to represent the annual emission rate of each pollutant (or consumption rate for water) for each generation source category. This same methodology was used across all source categories and across all scenarios.

APS included one fixed contract purchase for which environmental effects are not otherwise recorded as part of the baseload generation emission/consumption rates. This contract is for generation capacity delivered by Salt River Project ("SRP") at the SRP Agua Fria facility. Because the specific generation source for energy provided via the Agua Fria facility is not reported as part of the contract, APS assumed as a conservative estimate of environmental parameters related to energy provided via Agua Fria, that all energy delivered via Agua Fria is generated at that plant, which contains three 1960s vintage gas-fired steam units. Because emission/consumption rates were not provided to APS by SRP for the Agua Fria plant, environmental parameters from the APS Ocotillo Power Plant (steam units only) were averaged over the five-year benchmark period and used as a proxy for Agua Fria. Both Ocotillo and Agua Fria are similar types and vintage and employ similar emission control and cooling technology. Only the water consumption rate was adjusted (with a 14 percent discount) to account for the reuse of cooling tower blowdown at the Agua Fria plant by reintroduction into the SRP canal system.

Energy purchased to supplement APS' generation and fixed purchase contract is reported under the Purchased Power generation source category. Three "unit types" or sources are reported under this category, including market purchases, PWEC in 2001 and 2002 and renewable energy. PWEC is reported as a unique unit type because actual generation data was available for PWEC plants. Generation sources are not reported as part of the market purchase of energy, nor are environmental parameters associated with that energy. For purposes of this report, two conservative assumptions were made which may overstate the benchmark period, to allow calculation of emissions and water use associated with this "unit type." First, all market energy purchases were obtained from facilities typically available during high demand periods, most often either older steam units or simple cycle combustion turbines. Second, the plant-wide emission/consumption rates for APS' Ocotillo Power Plant was used as an adequate proxy for all market purchases between 1998 and 2002.

Three PWEC facilities came on-line in 2001 and 2002 - West Phoenix Unit 4, Redhawk Units 1 and 2, and Saguaro GT3. All three facilities are reported individually within Purchase Power source category and under the subheading PWEC. Data provided as part of the Track B bidding process was used to report emissions and consumption for those facilities.

Renewable energy purchases are also reported under the source category Purchase Power. Because such power was generally obtained from solar sources, the emissions/consumption rates for these facilities was assumed to be zero.

Emissions of each pollutant and water consumption were totaled for all generation source categories for each year, resulting in an annual emission/consumption rate. The average rates for those five years is reported as a benchmark for comparison with Scenarios 1 and 2.

#### Scenario 1: Year 2003 Analysis Utilizing Track B Contracts

The APS energy profile for Scenario 1 included four source categories: APS-owned generation, fixed contract purchases, Track B contracts and other purchased power. Actual reported generation data was applied from January 2003 through June 2003, and projected generation and power purchases for this scenario were applied between July and December of that year. Details of the values used to compile this profile are provided in Attachments 2 and 3.

Emission/consumption rates for APS generation unit types were projected by using the average unit-type rates from the Benchmark Scenario. Total pollutant emissions and water consumption were calculated using these rates.

Environmental parameters for the fixed purchase contract were calculated using the same five-year average rates for the Ocotillo Power Plant, as described above in the Benchmark Scenario.

Track B-related environmental parameters were calculated based on values reported by each of the successful bidders - PWEC, Panda Gila River, LP and PPL EnergyPlus, LLC. PWEC-wide emission/consumption rates were calculated based on purchases from

individual PWEC facilities and their reported respective *actual* rates (the PWEC Track B bid package reported both theoretical and actual environmental parameters). Most other Track B bidders reported theoretical emissions/consumption rates based on modeled engineering estimates. (Information provided by the other bidders appeared to consist of design data, not rates based on actual operations.)

Environmental parameters for PWEC facility purchases between January 2003 and June 2003 were reported and calculated under the purchased power source category. Other market purchases in the purchased power source category are reported as a single "unit type." It was assumed that energy purchases would be obtained from facilities of similar composition to those which provided bid packages during the Track B bidding process. Emission/consumption rates for this unit type were generated as the assemblage of all bidders in the Track B process who provided this information.

#### Scenario 2: Year 2003 Baseline Analysis Absent Track B Contracts

The APS energy profile for this scenario included three source categories: APS-owned generation, fixed contract purchases and purchased power. Actual reported generation data was applied from January 2003 through June 2003 and projected generation and power purchases for this scenario were applied between July and December of that year. Details of the values used to compile this profile are provided in Attachments 2 and 3.

Emission/consumption rates for APS-owned generation unit types were projected by using the average unit-type rates from the Benchmark Scenario timeframe. Total pollutant emissions and water consumption were back-calculated using these rates.

Environmental parameters for the fixed purchase contract were calculated in the same manner described above for the benchmark scenario.

Environmental parameters for PWEF facility purchases between January 2003 and June 2003 were reported and calculated under the Purchased Power source category. For this scenario, it was assumed that all market energy purchases would necessarily be obtained from facilities of similar composition to those which provided bid packages during the Track B bidding process. Other market purchases in the purchased power source category are reported as a single "unit type." Emission/consumption rates for this unit type were generated as the average of all bidders in the Track B process.

#### B. Analysis of Demographics

Track B bidders were asked to provide demographic information relating to location of their generation facilities and the population residing within census tracts located within a 50-mile radius. This study provides an overview analysis of this demographic data relative to the APS native load facilities.

## **Discussion**

As required by the ACC order, this report provides an analysis of the environmental effects of the Track B solicitation process against a benchmark of the environmental effects of APS' past five complete years of operations (1998 through 2002). Because the regional generation profile has changed significantly during the past two years and independently of Track B, APS has added a second modeled scenario to compare against both the benchmark and the scenario that included Track B contracts.

### APS Baseline Generation Portfolio (1998-2002)

A summary of air pollutant emissions and surface/groundwater consumption for the five-year APS Benchmark is provided in Table 1. Several assumptions were used to develop this information. First, only APS-owned generation and purchased power used to serve APS' native load are included. The analysis does not include power purchased for wholesale marketing, risk management and/or similar uses. Second, air pollutant emission and water consumption profiles for purchased power during the benchmark period are assumed to be similar to that of APS' Ocotillo Power Plant.

**Table 1 – APS Benchmark Generation Portfolio**

<b>Environmental Parameter</b>	<b>1998</b>	<b>1999</b>	<b>2000</b>	<b>2001</b>	<b>2002</b>	<b>Five Year Benchmark</b>
<b>Air (lbs/MWh)</b>						
NOx	3.30	3.15	3.29	2.99	2.83	<b>3.11</b>
SO2	2.67	2.30	2.06	1.99	1.94	<b>2.19</b>
CO2	1294.56	1310.62	1341.22	1306.28	1269.07	<b>1304.34</b>
PM10	0.18	0.18	0.17	0.16	0.16	<b>0.17</b>
CO	0.28	0.30	0.29	0.30	0.21	<b>0.27</b>
VOC	0.04	0.04	0.03	0.03	0.03	<b>0.03</b>
Hg	0.0000170	0.0000177	0.0000170	0.0000166	0.0000161	<b>0.0000169</b>
<b>Surface/ Groundwater (gal/MWh)</b>	440	449	429	427	414	<b>432</b>

The results of the analysis show the five-year APS benchmark to be favorably impacted by the addition of new natural gas-fired generation. During 2001 and 2002, new gas-fired generation became available. The higher efficiencies of such facilities are reflected in the reported data, particularly the annual results for 2002. Other improvements that may have contributed to the improvements in the 2002 data include improved operating efficiencies; higher capacity factors (particularly for the Palo Verde Nuclear Generating Station); burning of cleaner natural gas in place of fuel oil; and improved systems and operating controls.

Palo Verde's use of treated effluent for cooling water reduces APS' dependence on and use of surface water, groundwater and/or other valuable potable water sources and reflects positively when APS' benchmark water consumption rate is compared across other utilities. Redhawk Units 1 and 2 also use treated effluent for cooling water, further increasing generation capacity that does not use surface water, groundwater and/or other

valuable potable water sources. The favorable impact of this reduced dependence is reflected in APS' reduced water consumption rate for 2002.

#### Scenario 1 and Scenario 2

Changes in the regional generation profile similarly affect both Scenario 1 and Scenario 2, as it began to affect 2002 during the benchmark period. The utilization of newly constructed natural gas-fired power plants to support APS' increasing demand has the net effect of reducing the overall average of air emissions and water consumption rates. Based on the information reported by the Track B bidders, these newly constructed plants appear to be inherently more efficient from an emission/consumption rate perspective, which has been generally true for each new generation of plants.

A comparison of the benchmark impacts to the Track B effects does not address the question of whether Track B has an incremental beneficial environmental effect. For this reason, Scenario 2 was developed to reflect what APS' generation portfolio would have been absent Track B. Comparison of Track B results (Scenario 1) with Scenario 2 provides a more realistic representation of the actual environmental effects of the Track B process. The results of the both scenarios, the benchmark period, and year 2002 of the benchmark period, are provided in Table 2.

**Table 2 – Comparison of APS Benchmark to Track B Scenarios**

<b>Environmental Parameter</b>	<b>Benchmark (1998 – 2002) average</b>	<b>Benchmark Year 2002</b>	<b>Scenario 1 (2003 Track B)</b>	<b>Scenario 2 (2003 absent Track B)</b>
<b>Air (lbs/MWh)</b>				
NOx	3.11	2.83	2.61	2.60
SO2	2.19	1.92	1.96	1.96
CO2	1304.32	1269.07	1198.28	1212.31
CO	0.27	0.21	0.21	0.20
PM10	0.17	0.16	0.17	0.17
VOC	0.03	0.03	0.03	0.03
Hg	0.0000169	0.0000161	0.0000149	0.0000149
<b>Surface/ Groundwater (gal/MWh)</b>	432	414	378	382

It is important to consider these points when reviewing Table 2:

- In the Scenario 1 analysis, APS included the source categories of APS-owned generation, fixed contract purchases, Track B contracts and purchased power.
- Scenario 2 utilized source categories of APS-owned generation, fixed contract purchases and purchased power in the absence of the Track B bidding process. APS assumed the sources of the purchased power in Scenario 2 were the new gas-fired combined cycle plants, specifically any generation facility that offered the sale of power during the Track B bidding process, where environmental and generation data was reported. APS assumed this to be the case based on heat rates and other factors that provide these plants with a economic advantage over older, less efficient generating plants that may be available in the wholesale power market.
- Comparison of the two 2003 scenarios shows very similar environmental emission/consumption rates. This is reflective of the similarity of the generation

sources modeled for market purchase (and Track B contracts) under both scenarios. The slight reported benefit of Scenario 1 over Scenario 2 is the result of PWEC's Redhawk Power Plant and its use of effluent for cooling water purposes. It is important to note that the reported differences between Scenario 1 and Scenario 2 are likely within the error margins of the calculation and may not be statistically significant.

- Comparison of the benchmark average and the year 2002 data highlights the beginning of the introduction of the newly constructed natural gas-fired power plants. APS believes the trend reflected in 2002 is captured in Scenario 2 when projecting the benchmark into 2003.
- Although the water consumption rate is projected to decrease under either Scenario 1 or 2, they are still within approximately 10 percent of 2002 and are further reflective of the water constraints within the region. This decrease is relatively low when considering the very conservative estimates employed for water consumption rate estimates and the significant water consumption benefit provided by PWEC's Redhawk Power Plant.

### Demographics

Evaluation of the benchmark period reveals that the APS coal-fired power plants are located in rural areas, near their fuel source and the APS gas-fired power plants tend to be located nearer their end users to take advantage of economic and operational efficiencies. The gas-fired plants provide voltage stability critical to maintaining the reliability of the energy delivery system within the metropolitan Phoenix area. The location of specific

generating facilities for the purchased power during the benchmark period was not known.

Track B bidders were requested to provide information relative to populations within a 50-mile radius of their generation source. Analysis of the available information indicates these plants tended to be located nearer larger population centers, rather than in rural areas. The selected bidders' plants were all within 75 miles of a major metropolitan area (Phoenix, Tucson and Las Vegas).

### **III. Conclusions**

Several conclusions can be reached from this analysis. Perhaps the most significant is that any improvement seen in the air emission and water consumption rates resulting from a comparison of the five-year benchmark period to 2003 Track B portfolios was not the result of the Track B process per se. Rather, these improvements result from the availability since 2002 of additional natural gas-fired generation. Because of increased market demands and economics, this new generation would have become available and incorporated into APS' purchase power portfolio under either the Track B process or any other potential procurement process.

Comparison of the two-modeled scenarios showed little difference as measured by the reported environmental parameters. The resulting similarity of the two scenarios is reflective of the incorporation of the gas-fired generation newly available in the regional generation profile. Based on market evaluations, purchased power in the years following the benchmark period is most likely to utilize a greater proportion of newer natural gas generation capacity, both under Track B (Scenario 1) and under Scenario 2.

Comparison of both Scenarios 1 and 2 with the benchmark year 2002 highlights that the decreasing emission and consumption trends for 2003 were already underway as new natural gas-fire generation was introduced into the region in 2002.

Second and with respect to water consumption, the benchmark and the two-modeled scenarios are both favorably impacted by generation capacity that does not rely on surface water or groundwater for cooling purposes (APS Palo Verde Nuclear Generating Station and PWEC's Redhawk Units 1 and 2). This favorable impact is more pronounced in both 2003 scenarios as capacity from the Redhawk units is used by APS.

Third, construction of new generation capacity, and its incorporation into the regional profile, has not displaced any of APS' existing generation capacity, largely because of increased market demand for power. Thus, the base load portion of APS' power portfolio, consisting primarily of coal and nuclear generation, was not significantly impacted by the Track B process. By that we mean that the economics of this generation are such that it is not displaced by new gas-fired generation. In particular, the coal plants produce power for a consistent price much lower than any of the new gas-fired plants, and neither the price nor the availability of coal is subject to the vagaries of the natural gas market.

Demographic information with respect to plant location alone provided little insight of value into relative environmental effects. The selected Track B facilities are all located within 75 miles of a major metropolitan area (Phoenix, Tucson and Las Vegas). Based upon the air emissions and water consumption modeling information submitted with the bids there would be no significant effects on either the environment or the local populations.

**Attachment 1:**

**Track B Submittals: Environmental**

## SUMMARY OF ENVIRONMENTAL INFORMATION FOR PINNACLE WEST ENERGY'S SILVERHAWK POWER PLANT

The following information was prepared by the Pinnacle West Capital Corporation Environmental Health and Safety Department at the request of Pinnacle West Energy Corporation.

Pinnacle West Energy Corporation's (PWEC) Silverhawk Power Plant is a natural gas-fired combined cycle facility located in Apex Valley approximately twenty-five miles north east from downtown Las Vegas, Nevada. The Silverhawk plant consists of two combustion turbine/duct burner pairs in a combined cycle configuration with a nominal capacity of 570 MW. The facility is currently under construction and is scheduled to be completed in June 2004.

The unit is equipped with dry-low NOx burners and Selective Catalytic Reduction systems to control NOx emissions and catalytic oxidizer systems to control CO emissions. It is permitted at 2.5 ppm NOx, however the plant is required to conduct a 3-year demonstration to determine if lower emission rates are achievable. If lower rates can be achieved the permitted levels will be reduced.

The unit is also equipped with an air-cooled condenser and Zero Liquid Discharge System consisting of a brine concentrator to minimize water use and eliminate offsite discharge of plant effluent.

### A. WATER

#### Water Use Data

Plant		Gallons	Acre Feet	MWh	Gallons/MWh (b)
Silverhawk					
	Design (a)	70,956,000	220	4,493,880	16

#### Notes:

(a) The Silverhawk Power Plant is currently under construction and has not yet operated. The design water use and generation data are based on a 90% capacity factor.

(b) Calculations based on gross MWh.

#### Groundwater Modeling

The Silverhawk Power Plant was not required to perform a groundwater modeling analysis for the Nevada Division of Water Resources nor for the Nevada Bureau of Water Pollution Control.

## B. AIR

### Air Emissions

Plant/Unit	SO2 (lb/MWh)	NOx (lb/MWh)	CO2 (lb/MWh)	PM10 (lb/MWh)	CO (lb/MWh)	VOC (lb/MWh)	Hg (lb/GWh)
Silverhawk Permit (a)	0.0050	0.1506	908.6	0.0721	0.2741	0.0416	0.0021

#### Note:

The Silverhawk Power Plant is currently under construction and has not yet operated. The emission rates for SO2, NOx, PM10, CO and VOC are based on the maximum annual potential to emit permitted by Clark County Air Quality Management District (DAQM). The CO2 and Hg emission rates are based on EPA factors. All emission rates are calculated using gross MWh based on 6000 hours of operation without duct burners and 2000 hours of operation with duct burners and include start-up/shutdown periods.

### Air Quality Modeling

As a requirement to begin construction under the Authority to Construct Permit for the Silverhawk Power Plant (Permit No. A1584), an air quality model assessment was performed for the Clark County Department of Air Quality Management District (DAQM). The model assessment was performed for NOx, CO, SO2 and PM10 using the USEPA approved ISCST3 model, and was based on the permitted maximum potential emissions from the facility. The predicted model impacts were compared to the National Ambient Air Quality Standards (NAAQS). The NAAQS were set by EPA and are a guideline to ensure that public health and the environment are protected. The results presented below show model impacts from the two units are all below the applicable NAAQS.

Criteria Pollutant	Model Impact (ug/m3)	NAAQS (ug/m3)	Per Cent of NAAQS
NOx			
Annual Average	0.73	100	0.73
CO			
1-Hr Average	12,302	40,000	30.7
8-Hr Average	840	10,000	8.4
SO2			
3-Hr Average	5.84	1,300	0.45
24-Hr Average	1.25	365	0.34
Annual Average	0.04	80	0.05
PM10			
24-Hr Average	18.7	150	12.4
Annual Average	0.56	50	1.1

**Note:**

Concentrations in micrograms per cubic meter (ug/m3)

**C. DEMOGRAPHICS**

The following table provides a list of all cities/towns located within a 50-mile radius of the Silverhawk Power Plant and their approximate populations. The source of this information is the U.S. Census 2000.

<b>Community</b>	<b>Approx. Population</b>
Blue Diamond CDP	282
Boulder City city	14,966
Enterprise CDP	14,676
Goodsprings CDP	232
Henderson city	175,381
Las Vegas city	478,434
Moapa Town CDP	928
Moapa Valley CDP	5,784
Mount Charleston CDP	285
North Las Vegas city	115,488
Paradise CDP	186,070
Spring Valley CDP	117,390
Sunrise Manor CDP	156,120
Winchester CDP	29,958
<b>Total</b>	<b>1,295,994</b>

**D. ENVIRONMENTAL PERFORMANCE**

No fines or penalties have been assessed against the Silverhawk Power Plant or against Pinnacle West Energy Corporation for failure to comply with applicable environmental regulations or permit requirements. Pinnacle West Energy's affiliated generating company, Arizona Public Service Company, paid a total of \$19,050 during the 5-year period 1998 through 2002 for the following violations.

<b>Year</b>	<b>Description</b>
1998	Violation of Maricopa County solvent degreasing rule at the West Phoenix Power Plant (\$600 fine).
1999	Violation of Arizona Revised Statute 41-2123 at the West Phoenix Power Plant and Deer Valley facility for failure to meet gasoline oxygenate requirements (2/\$300 fines).
2000	Violation of Clean Water Act at the Cholla Power Plant for accidental discharge from a bottom ash pipeline (\$15,000 fine).
2000	Violation of Migratory Bird Treaty Act for golden eagle electrocution on distribution line (\$2,500 fine).
2002	Violation of the Migratory Bird Act for illegally removing an active raven's nest (\$350 fine).

## SUMMARY OF ENVIRONMENTAL INFORMATION FROM PINNACLE WEST ENERGY CORPORATION'S SAGUARO COMBUSTION TURBINE FACILITY

The following information was prepared by the Pinnacle West Capital Corporation Environmental Health and Safety Department at the request of Pinnacle West Energy Corporation.

Pinnacle West Energy Corporation's (PWEC) facility consists of an 80 MW natural gas-fired simple cycle combustion turbine (CT3) located at the Saguaro Power Plant. The Saguaro Power Plant is located at Red Rock, Arizona approximately 32 miles northwest of Tucson, Arizona. CT3 is equipped with dry-low NOx burners and began commercial operation in June 2002. It is operationally limited, as its NOx emissions cannot exceed 39 tpy and CO cannot exceed 97.5 tpy.

Information in this summary is for calendar year 2002.

### A. WATER

#### Water Use Data

Plant	Gallons	Acre Feet	MWh	Gallons/MWh (b)
Saguaro GT3				
2002 (a)	2,900,000	8.9	46,560	62

#### Notes:

(a) Water consumption value is based on the reverse osmosis inlet integrator meter.

(b) Calculations based on gross MWh

#### Groundwater Modeling

Groundwater use for CT3 was projected to be so low relative to the allotment for the Saguaro Power Plant that modeling was not required by the Arizona Department of Water Resources.

### B. AIR

#### Air Emissions

Plant/Unit	SO2 (lb/MWh)	NOx (lb/MWh)	CO2 (lb/MWh)	PM10 (lb/MWh)	CO (lb/MWh)	VOC (lb/MWh)	Hg (lb/GWh)
Saguaro CT3	0.0043	0.2019	827.37	0.0387	0.2534	0.0387	0.0031

#### Note:

Saguaro CT3 emission rate calculations for NOx, CO and CO2 are based on Continuous Emission Monitoring System data; PM10 and VOC emission rate calculations are based on source test data; SO2 and Hg emission

rate calculations are based on emission factors. All emission rates are calculated using gross MWh and include start-up/shutdown periods.

## Air Quality Modeling

As a requirement to construct and operate CT3 under the Title V permit for the Saguaro Power Plant (Permit No. V20601.R01), the Pinal County Air Quality Control District (PCAQD) determined qualitatively that emissions from CT3 would not cause an exceedance of the National Ambient Air Quality Standards (NAAQS). The NAAQS were set by EPA and are a guideline to ensure that public health and the environment are protected. In their assessment, PCAQD noted that CT3 would only add limited emissions and have negligible impact on the ambient air quality levels.

## C. DEMOGRAPHICS

The following table provides a list of all cities/towns located within a 50-mile radius of the Saguaro Power Plant and their approximate populations. The source of this information is the U.S. Census 2000.

Community	Approx. Population
Chuichu CDP	339
Eloy city	10,375
Florence town	17,054
Ak-Chin Village CDP	669
Arizona City CDP	4,385
Catalina CDP	7,025
Catalina Foothills CDP	53,794
Cibola CDP	172
East Sahuarita CDP	1,419
Hayden town	892
Kearny town	2,249
Mammoth town	1,762
Marana town	13,556
Oracle CDP	3,563
Oro Valley town	29,700
Sahuarita town	3,242
Santa Rosa CDP	438
South Tucson city	5,490
Tucson city	486,699
Tucson Estates CDP	9,755
Winkelman town	443
Casa Grande city	25,224
Coolidge city	7,786
Queen Creek town	4,316

<b>Community</b>	<b>Approx. Population</b>
Queen Valley CDP	820
Sacaton CDP	1,584
Stanfield CDP	651
<b>Total</b>	<b>693,402</b>

#### **D. ENVIRONMENTAL PERFORMANCE**

Since operations began in 2002 no fines or penalties have been assessed against the Saguaro CT3 facility or against Pinnacle West Energy Corporation for failure to comply with applicable environmental regulations or permit requirements. Pinnacle West Energy's affiliated generating company, Arizona Public Service Company, who has been contracted to operate CT3 on behalf of PWEC, paid a total of \$19,050 during the 5-year period 1998 through 2002 for the following violations.

<b>Year</b>	<b>Description</b>
1998	Violation of Maricopa County solvent degreasing rule at the West Phoenix Power Plant (\$600 fine).
1999	Violation of Arizona Revised Statute 41-2123 at the West Phoenix Power Plant and Deer Valley facility for failure to meet gasoline oxygenate requirements (2/\$300 fines).
2000	Violation of Clean Water Act at the Cholla Power Plant for accidental discharge from a bottom ash pipeline (\$15,000 fine).
2000	Violation of Migratory Bird Treaty Act for golden eagle electrocution on distribution line (\$2,500 fine).
2002	Violation of the Migratory Bird Act for illegally removing an active raven's nest (\$350 fine).

## SUMMARY OF ENVIRONMENTAL INFORMATION FOR PINNACLE WEST ENERGY CORPORATION'S REDHAWK POWER PLANT

The following information was prepared by the Pinnacle West Capital Corporation Environmental Health and Safety Department at the request of Pinnacle West Energy Corporation.

Pinnacle West Energy Corporation's (PWEC) Redhawk Power Plant is a natural gas-fired combined cycle facility located approximately sixty miles west-southwest from downtown Phoenix, near Arlington, Arizona. The Redhawk plant was originally permitted for up to four combined cycle units (plant capacity of 2,120 MW), but only two units were constructed. The current capacity of the plant is approximately 1,060 MW. CC1 and CC2 began operation in June/July 2002.

CC1 and CC2 are equipped with dry-low NOx burners and Selective Catalytic Reduction systems (SCR) to control NOx emissions. The units are permitted at 3.0 ppm NOx, however PWEC is required to conduct a 2-year demonstration to determine if lower emission rates are achievable. If lower rates can be achieved the permitted levels will be reduced.

The Redhawk Power Plant is designed to be cooled primarily by treated effluent purchased from Arizona Public Service Company's Palo Verde Nuclear Power Plant. The Redhawk facility is also equipped with a Zero Liquid Discharge system consisting of a brine concentrator and crystallizer to minimize water use and eliminate the need for large evaporation ponds for plant effluent.

Information presented in this summary is for calendar year 2002.

### A. WATER

#### Water Use

Plant		Gallons	Acre Feet	MWh	Gallons/MWh(c)
RedHawk					
	2002 (a)	538,472,083	1,652.5	2,016,175	267
	Unit 1 (b)	297,394,538	912.7	1,113,520	267
	Unit 2 (b)	241,077,544	739.8	902,655	267

#### Notes:

(a) Redhawk Effluent Delivery in 2002 = 2858.4 AF where 467.8 AF were used to fill supply pond for the first time and 821.5 AF were used for initial startup, flushing, and filling of systems and initial boiler blowdowns. Only 1569.1 AF was used for power production and 83.4 AF were pumped from groundwater wells.

(b) Water consumption data was not metered on a per unit basis and were therefore calculated as a proportion of the generation total of each unit.

(c) Calculations based on gross MWh.

## Groundwater Modeling

*Evaluation of Groundwater Responses to Pumping for Proposed Power Plants in the Centennial Wash Area, Maricopa County, Arizona.* Model Simulation Report. Prepared for Duke Energy North America, Pinnacle West Energy, and Sempra Energy Resources. Prepared by Peter Mock Groundwater Consulting, Inc. Phoenix, Arizona. July 7, 2000.

### Summary:

Based on modeled pumping rates of 3,400 acre-feet from the Redhawk Power Plant (greater than the facility's Type I right of 3,156 acre-feet), the model predicts a 40 to 45 foot drawdown after 30 years beneath the Redhawk property. Since Redhawk was designed to use treated effluent as its primary source of cooling water the Plant will require only 100-300 acre feet of groundwater per year for cooling needs. Actual groundwater use in 2002 was 83.4 acre-feet, far below the modeled pumping rate of 3,400 acre-feet.

## B. AIR

### Air Emissions

Plant/Unit	SO2 (lb/MWh)	NOx (lb/MWh)	CO2 (lb/MWh)	PM10 (lb/MWh)	CO (lb/MWh)	VOC (lb/MWh)	Hg (lb/GWh)
Redhawk							
CC1	0.0044	0.0708	864.0	0.0199	0.0915	0.0033	0.00189
CC2	0.0038	0.0673	754.97	0.0273	0.0859	0.0041	0.00165

#### Note:

Redhawk CC1 and CC2 emission rate calculations for NOx, CO and CO2 are based on Continuous Emission Monitoring System data; PM10 and VOC emission rate calculations are based on source test data; SO2 and Hg emission rate calculations are based on emission factors. All emission rates are calculated using gross MWh and include start-up/shutdown periods.

### Air Quality Modeling

As a requirement to construct and operate the Redhawk Power Plant under the Title V operating permit (Permit No. V99-013), PWEC performed an air quality model assessment for the Maricopa County Environmental Services Department. The model assessment was performed for NOx, CO and PM10 using the USEPA approved ISCST3 model, and was based on the maximum emissions from all four combined cycle units. The predicted model impacts were compared to the National Ambient Air Quality Standards (NAAQS). The NAAQS were set by EPA and are a guideline to ensure that public health and the environment are protected. The results presented below show model impacts from all four units are all below the applicable NAAQS.

Criteria Pollutant	Model Impact (ug/m3)	NAAQS (ug/m3)	Per Cent of NAAQS
NOx			
Annual Average	1.95	100	1.95
CO			
1-Hr Average	1,669	40,000	4.2
8-Hr Average	426	10,000	4.3
PM10			
24-Hr Average	11.9	150	7.9
Annual Average	1.7	50	3.4

**Note:**

Concentrations in micrograms per cubic meter (ug/m3)

### C. Demographics

The following table provides a list of all cities/towns located within a 50-mile radius of the Redhawk Power Plant and their approximate populations. The source of this information is the U.S. Census 2000.

Community	Approx. Population
Wickenburg town	5,082
Avondale city	35,883
Buckeye town	6,537
El Mirage city	7,609
Glendale city	218,812
Goodyear city	18,911
Litchfield Park city	3,810
Maricopa CDP	1,040
Paradise Valley town	13,664
Peoria city	108,364
Phoenix city(a)	660,522
Sun City CDP	38,309
Sun City West CDP	26,344
Surprise city	30,848
Tempe city	158,625
Tolleson city	4,974
Youngtown town	3,010
Gila Bend town	1,980
total	1,344,324

**Note:**

(a) Approximately one half the land area of the City of Phoenix falls within the 50-mile radius. It was assumed that one half the stated population of the city was within the area.

### D. Environmental Performance

Since operations began in 2002 no fines or penalties have been assessed against the Redhawk Power Plant or against Pinnacle West Energy Corporation for failure to comply with applicable environmental regulations or permit requirements. Pinnacle West Energy's affiliated generating

company, Arizona Public Service Company, paid a total of \$19,050 during the 5-year period 1998 through 2002 for the following violations.

Year	Description
1998	Violation of Maricopa County solvent degreasing rule at the West Phoenix Power Plant (\$600 fine).
1999	Violation of Arizona Revised Statute 41-2123 at the West Phoenix Power Plant and Deer Valley facility for failure to meet gasoline oxygenate requirements (2/\$300 fines).
2000	Violation of Clean Water Act at the Cholla Power Plant for accidental discharge from a bottom ash pipeline (\$15,000 fine).
2000	Violation of Migratory Bird Treaty Act for golden eagle electrocution on distribution line (\$2,500 fine).
2002	Violation of the Migratory Bird Act for illegally removing an active raven's nest (\$350 fine).

## SUMMARY OF ENVIRONMENTAL INFORMATION FOR PINNACLE WEST ENERGY CORPORATION'S WEST PHOENIX COMBINED CYCLE FACILITY

The following information was prepared by the Pinnacle West Capital Corporation Environmental Health and Safety Department at the request of Pinnacle West Energy Corporation.

Pinnacle West Energy Corporation's (PWEC) facility consists of two natural gas-fired combined cycle units (CC4 and CC5) located at the West Phoenix Power Plant. The plant is located at 4606 West Hadley in western metropolitan Phoenix, Arizona. CC4 has an approximate capacity of 120 MW and began operation in June 2001. It is equipped dry-low NOx burners to control NOx emissions and a catalytic oxidizer system for CO control. CC5 has approximate capacity of 530 MW and is currently under construction. It is scheduled to be completed by June 2003. CC5 is equipped with dry-low NOx burners and Selective Catalytic Reduction systems (SCR) to control NOx emissions, and catalytic oxidizer systems for CO control. Both units are equipped with Zero Liquid Discharge Systems (brine concentrator on CC4, and brine concentrator/crystallizer on CC5) to minimize water use and eliminate offsite discharge of plant effluent.

CC4 and CC5 are permitted to operate under an emissions cap, which cannot be exceeded. In order to prevent total NOx emissions from exceeding the cap PWEC was also required to install an SCR to significantly reduce NOx emissions on an existing combined cycle unit located at the West Phoenix Power Plant, which is owned and operated by PWEC's affiliated generating company, Arizona Public Service Company.

### A. WATER

#### Water Use

Plant		Gallons	Acre Feet	MWh	Gallons/MWh (c)
West Phoenix CC4					
	2001	238,249,270	734	475,582	501
	2002	271,293,238	833	475,173	571
	Modeled (a)	309,557,000	950	1,024,920	302
West Phoenix CC5					
	Modeled (b)	1,098,124,610	3370	4,178,520	263

#### Notes:

- Since start-up the West Phoenix CC4 brine concentrator has not operated as designed. Modeled water use is derived from historic plant water use and engineering design data for CC4, and used as basis for predicting WPPP water usage in the Certificate of Environmental Compatibility application and the resulting Hargis + Associates modeling report. The modeled water use assumes the brine concentrator operates at its design capacity. The brine concentrator, which has recently been upgraded is now in operation and is expected to operate reliably as designed.
- West Phoenix CC5 has not yet operated. Water use (and MWh) assume 90% capacity factor. Modeled water use derived from historic plant water use and engineering design data for CC5. Values were used as basis for predicting WPPP water usage in the Certificate of Environmental Compatibility application

and the resulting Hargis + Associates modeling report.

(c) Calculations based on gross MWh.

### Groundwater Modeling

*Groundwater Assessment, West Phoenix Power Plant Aquifer Protection Permit Application Package, Appendix 7.D.* Prepared for Pinnacle West Capital Corporation. Prepared by Hargis + Associates, Inc. Tempe, Arizona. October 9, 2000.

#### Summary:

Two groundwater withdrawal scenarios were simulated. In the first simulation (Scenario A) groundwater withdrawal was assumed to be 4,000 acre-feet, which represents approximately 87% of the total groundwater right for the property (4,600 acre-feet). In the second simulation (Scenario B) groundwater withdrawal was increased to 5,000 acre-feet.

The results of groundwater modeling indicated that the proposed future increase in groundwater withdrawal at the site (Scenario A) is not expected to result in a significant decrease in water level in the nearby non-West Phoenix Power Plant wells of record (2 feet in the Upper Alluvial Unit (UAU) and 10 in the Lower Alluvial Unit (LAU)). In addition, the incremental increase in drawdown between Scenarios A and B is also not expected to be significant. Therefore, withdrawing groundwater at a rate greater than the existing groundwater right for the property (Scenario B) is not expected to create excessive drawdown in nearby non-West Phoenix Power Plant wells of record (2.6 feet in the UAU and 12 in the LAU). The groundwater model results also show there is little likelihood that the increased withdrawal will cause migration of contaminants from the UAU to the LAU.

It should be noted that the existing groundwater right for the property cannot be exceeded. However, PWEC has the option to purchase additional water from other sources should usage exceed the allocated property water right.

### B. AIR

#### Air Emissions

Plant/Unit	SO <sub>2</sub> (lb/MWh)	NO <sub>x</sub> (lb/MWh)	CO <sub>2</sub> (lb/MWh)	PM <sub>10</sub> (lb/MWh)	CO (lb/MWh)	VOC (lb/MWh)	Hg (lb/GWh)
West Phoenix							
CC4 (a)	0.0046	0.2163	953.63	0.0505	0.0278	0.0101	0.0022
CC5 (b)	0.0043	0.0912	375.24	0.0354	0.0293	0.0145	0.0009

Notes:

- (a) West Phoenix CC4 emission rate calculations for NO<sub>x</sub>, CO and CO<sub>2</sub> are based on Continuous Emission Monitoring System data; PM<sub>10</sub> and VOC emission rate calculations are based on source test data; SO<sub>2</sub> and Hg emission rate calculations are based on emission factors. All emission rates are calculated using gross MWh and include start-up/shutdown periods.
- (b) West Phoenix CC5 is currently under construction and therefore no actual operating data is available. The emission rate calculations are based on a 90% capacity operating scenario provided to Maricopa County during permitting process, and use emission factors for NO<sub>x</sub>, CO, CO<sub>2</sub>, PM<sub>10</sub>, VOC, SO<sub>2</sub> and Hg. All emission rates are calculated using gross MWh and include start-up/shutdown periods.

### Air Quality Modeling

As a requirement to construct and operate under the Title V permit for the West Phoenix Power Plant (Permit No. V95-006), PWEC performed an air quality model assessment for the Maricopa County Environmental Services Department. The model assessment was performed for SO<sub>2</sub>, CO and PM<sub>10</sub> using the USEPA approved ISCST3 model. The modeling was based on the emissions from CC4 and CC5. The predicted model impacts were compared to the National Ambient Air Quality Standards (NAAQS). The NAAQS were set by EPA and are a guideline to ensure that public health and the environment are protected. The results presented below show model impacts from CC4 and CC5 are below the applicable NAAQS.

Criteria Pollutant	Model Impact (ug/m3) (a)	NAAQS (ug/m3)	Per Cent of NAAQS
SO <sub>2</sub>			
3-Hr Average	0.71	1300	0.05
24-Hr Average	0.34	365	0.09
Annual Average	< 0.34	80	0.42
CO			
1-Hr	753.0	40,000	1.88
8-HR	328.0	10,000	3.28
PM <sub>10</sub>			
24-HR	4.30	150	2.9
Annual	0.76	50	1.5

**Note:**

(a) Concentrations are in micrograms per cubic meter (ug/m3)

### C. DEMOGRAPHICS

The following table provides a list of all cities/towns located within a 50-mile radius of the West Phoenix Power Plant and their approximate populations. The source of this information is the U.S. Census 2000.

Community	Approx. Population
-----------	-----------------------

<b>Community</b>	<b>Approx. Population</b>
Avondale city	35,883
Buckeye town	6,537
El Mirage city	7,609
Glendale city	218,812
Goodyear city	18,911
Litchfield Park city	3,810
Maricopa CDP	1,040
Paradise Valley town	13,664
Peoria city	108,364
Phoenix city	1,321,045
Scottsdale city	202,705
Sun City CDP	38,309
Sun City West CDP	26,344
Surprise city	30,848
Tempe city	158,625
Tolleson city	4,974
Youngtown town	3,010
Black Canyon City CDP	2,697
Carefree town	2,927
Cave Creek town	3,728
Chandler city	176,581
Fountain Hills town	20,235
Gilbert town	109,697
Guadalupe town	5,228
Mesa city	396,375
New River CDP	10,740
Rio Verde CDP	1,419
Sun Lakes CDP	11,936
Casa Grande city	25,224
Coolidge city	7,786
Queen Creek town	4,316
Queen Valley CDP	820
Sacaton CDP	1,584
Stanfield CDP	651
Gila Bend town	1,980
<b>total</b>	<b>2,984,414</b>

#### **D. ENVIRONMENTAL PERFORMANCE**

No fines or penalties have been assessed against West Phoenix CC4/CC5 or against Pinnacle West Energy Corporation for failure to comply with applicable environmental regulations or permit requirements. Pinnacle West Energy's affiliated generating company, Arizona Public Service Company, who has been contracted to operate CC4 and CC5 on behalf of PWEC, paid a total of \$19,050 during the 5-year period 1998 through 2002 for the following violations.

<b>Year</b>	<b>Description</b>
-------------	--------------------

Year	Description
1998	Violation of Maricopa County solvent degreasing rule at the West Phoenix Power Plant (\$600 fine).
1999	Violation of Arizona Revised Statute 41-2123 at the West Phoenix Power Plant and Deer Valley facility for failure to meet gasoline oxygenate requirements ( 2/\$300 fines).
2000	Violation of Clean Water Act at the Cholla Power Plant for accidental discharge from a bottom ash pipeline (\$15,000 fine).
2000	Violation of Migratory Bird Treaty Act for golden eagle electrocution on distribution line (\$2,500 fine).
2002	Violation of the Migratory Bird Act for illegally removing an active raven's nest (\$350 fine).

**Panda Gila River, L.P.**

**Attachment 3**

**Gila River Power Station Environmental Information**

**Prepared for:**

**Arizona Public Service Company**

*April 4, 2003*

### Attachment 3

#### Gila River Power Station

#### Environmental Information

##### *Emission & Consumption Information*

The emissions information in the following Table is based on maximum permitted ton per year for parameters with permit limits. AP-42 emission factors are used for parameters with no permit limit.

**Table 1. Emission & Consumption Matrix**

ITEM		CATEGORY	RESPONDENT VALUE	NOTES
1	CO2 (lb/MWh)	3	896	A, B
2	NOx (lb/MWh)	4	0.09	B, C
3	SO2 (lb/MWh)	4	0.01	B, C
4	PM (lb/MWh)	4	0.04	B, C
5	CO (lb/MWh)	4	0.05	B, C
6	VOC (lb/MWh)	4	0.02	B, C
7	Hg (lb/GWh)	4	0.002	A, B
8	Water Consumption (gal/MWh)	3	205	
9	Primary Water Source	2	Ground	
10	Population (within 50 miles)	2	>100K	
11	Penalties (last 5 years)	4	\$0	

**NOTES:**

- A. No permit limit for this parameter. Emissions based on emission factors in AP-42 Chapter 1.4 and maximum design heat input values for the entire plant.
- B. Calculations use tons/year divided by megawatt-hours (MWh) assuming 100% capacity factor (8760 hrs/yr \* 2200 MW (gross))
- C. Emissions calculated from permit limits

**SOURCES:**

Gila River Power Station Air Permit V99-018, Dated 8/20/01  
Dames & Moore, Well Impact Analysis, 8/11/00

#### *I. Air Quality Modeling Summary*

Modeling of estimated criteria pollutant impacts has demonstrated that National Ambient Air Quality Standards (NAAQS) and allowable PSD increments will not be violated.

PPL Energy Plus

# Sundance Energy Environmental Matrix

Item	Category	Respondant Value	Permitted Value	4	3	2	1
1	CO <sub>2</sub> (LBS/MWH)	117.1	NA	0-500	500-1,000	1,000-2,000	>2,000
2	NO <sub>x</sub> (LBS/MWH)	0.23	0.54	0-1.0	1.0-5.0	5.0-10.0	>10.0
3	SO <sub>2</sub> (LBS/MWH)	0.006	0.02	0-1.0	1.0-5.0	5.0-10.0	>10.0
4	PM (LBS/MWH)	0.014	0.16	0-0.1	0.1-0.25	0.25-1.0	>1.0
5	CO (LBS/MWH)	0.08	0.33	0-0.25	0.25-0.5	0.5-1.0	>1.0
6	VOC (LBS/MWH)	0.0392	0.10	0-0.025	0.025-0.05	0.05-0.1	>0.1
7	Hg (LBS/MWH)	NA	NA	0-0.005	0.005-0.01	0.01-0.1	>0.1
8	Water Consumption (GAL/MWH)	72	NA	1-100	100-500	500-1,000	>1,000
9	Primary Water Source	CAP	NA	Effluent	Surface	Ground	Other
10	Population (within 50 miles)	200,679	NA	1-10,000	10,000-100,000	100,000-1,000,000	>1,000,000
11	Penalties (within last 5 years)	\$0	NA	\$0-\$25,000	\$25,000-\$100,000	\$100,000-\$250,000	>\$250,000

## NOTES:

\* NOx and Co values include startups and shutdowns

Permit Limits for startup and shutdowns are:

NOX - 18.61 lb startup (30 minutes) and 2.57 lbs shutdown (6 minutes)

CO - 7.36 lb startup (30 minutes) and 0.07 lbs shutdown (6 minutes)

Startup and shutdown periods shall not exceed 1,000 per year per unit.

\*\* Consumptive water use includes 52,638 gal/min input minus 23,975 available for irrigation reuse (total plant)

\*\*\* Population within 25 miles is 155,567

Consumptive Water Use

Flushes 12000000

MWH 985500

Gal per MWH 12.17656

Turbines Uses

60 gal/min/turbine - demin

Hourly gallons/turbine 3600

Raw water gross up 4680

Gal/Mwh 104

TOTAL GAL/MWH 116.2

Report consumption 52638

Gal/Mwh 116.9733

## PPL Sundance Energy Air Quality Modeling Executive Summary

Dispersion modeling prepared for the Sundance Energy facility demonstrated that all air quality impacts would be well below all applicable federal and State of Arizona ambient air quality standards. A Prevention of Significant Deterioration (PSD) construction permit, Title V operating permit, and Title IV Acid Rain permit were issued by the Pinal County Air Quality Control District (PACQCD) on July 21, 2001 as Permit #V20613.000. Sundance Energy became operational in July 2002. This summary presents the Best Available Control Technology (BACT) emission limits approved by the PACQCD and the results of air dispersion modeling submitted with the permit application.

### Facility Description

The Sundance Energy facility is permitted as a nominal 540 MW natural gas fired simple cycle power generation facility. Twelve identical General Electric LM6000 combustion turbines generate approximately 45 MW each. Sundance Energy will combust natural gas only.

Sundance Energy is permitted as a "phased construction" facility. Currently, Sundance Energy has constructed and is operating 10 LM6000 turbines for a nominal load of 450 MW. For the second phase, Sundance Energy has the option to install two more LM6000 turbines and increase the nominal load to 540 MW.

The simple cycle power facility is primarily used to generate electric power to meet peak system load requirements. The LM6000 turbines are capable of rapid start-up enabling the plant to quickly respond to system demand. To meet the projected power demand, each turbine is permitted to operate a maximum of 7,500 hours per year including 6,500 hours per year at full load operation and 1,000 hours with a startup and shutdown of the units.

### BACT Permit Limits

Table 1 shows the BACT emission limits for the Sundance Energy facility.

Table 1 Sundance Energy Emission Limits			
Pollutant	Control Technology	BACT Limit <sup>1</sup>	Averaging period
Nitrogen Oxide (Nox)	Selective Catalytic Reduction and Water Injection	5.0 ppmvd	3-hour
Carbon Monoxide (CO)	Oxidation Catalyst and Good	15.0 ppmvd	3-hour

	Combustion Practice		
Fine Particulates (PM10)	Use of pipeline quality natural gas	7.0 lbs/hr	1-hour
Volatile Organic Compounds (VOC)	Oxidation Catalyst and Good Combustion Practice	4.5 lbs/hr	1-hour
Sulfur Dioxide (SO2)	Use of pipeline quality natural gas	Maintain contractual commitment with pipeline gas supplier demonstrating a total sulfur content of 20 grains / 100 standard cubic feet or less	

<sup>1</sup> ppmvd: parts per million at 15% O<sub>2</sub>

### PSD Dispersion Modeling

Dispersion modeling was completed with methods and data approved by the PCAQCD. Emissions were calculated based upon the BACT limits identified in the permit process. The Industrial Source Complex Short Term (ISCST3) dispersion model was used for the ambient impact analyses. The ISCST3 model is a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground-level elevations can exceed the stack heights of the emission sources. The modeling results of all applicable pollutant ambient air concentrations for their respective averaging periods were compared against the Arizona Ambient Air Quality Standards (AAAQS) and the PSD Class II increment consumption.

Receptors (geographical points to evaluate pollutant concentrations) were set at 25-meter intervals around the property boundary. Outside the property boundary, receptors were set at 100-meter intervals to three kilometers, and 200-meter intervals from three to ten kilometers. Because the only complex terrain (terrain higher than the stack height) exists from the west to the northwest of the facility, extra receptors were set at 100-meter intervals in the high terrain area.

The results of the modeling, shown in Table 2, demonstrated that the Sundance Energy facility will be in compliance with all applicable federal and state air quality laws, regulations and standards.

Table 2 Sundance Energy Predicted Maximum Air Quality Impacts 12 LM6000 Turbines				
Pollutant	Averaging Period	Maximum Concentration ( $\mu\text{g}/\text{m}^3$ )	Percent of Arizona Ambient Air Quality Standard	Percent of Class II Increment
NO <sub>2</sub>	Annual	1.40	1.40	5.6
CO	1 hour	58	0.1	NA
	8 hour	22	0.2	NA
PM <sub>10</sub>	24 hour	4.74	3.2	12.2
	Annual	0.93	1.4	4.1
Formaldehyde	1 hour	0.76	3.8	NA
	24 hour	0.14	1.7	NA
	Annual	0.026	32.5	NA

### Federal Class I Areas

Potential impacts to air quality and air quality related values (AQRV) were evaluated for Class I airsheds located within 100 kilometers of the Sundance Energy facility. The closest boundary of U.S. Forest Service Superstition Wilderness is approximately 57 kilometers north-northeast. The closest boundary of the National Park Service West Saguaro National Park is approximately 75 kilometers south-southeast. The Class I area analysis was completed using the EPA-approved CALPUFF dispersion and atmospheric chemical transformation model. The Class I impact analyses were reviewed and approved by the respective federal land managers. The results of the analysis demonstrated that potential effects to visibility and acid deposition would be below the significance levels established by the federal land managers of the respective Class I areas.

## PPL Sundance Energy Groundwater Modeling Executive Summary

### Introduction

The PPL Sundance Energy facility (Sundance) is a nominal 540 megawatt (MW) natural gas-fired simple cycle peaking electrical generating facility. Water obtained from the Central Arizona Project (CAP) is the primary source of water for the Facility. The use of groundwater is planned only as a backup source of water during interruptions of CAP water due to maintenance or unscheduled events of a duration that would exhaust the substantial on-site water storage facilities. PPL Sundance Energy has been operational since July 2002 and has used no groundwater to date for operations.

This document describes the expected consumptive water use for the operation of Sundance, and demonstrates the maximum predicted groundwater drawdown. If the maximum amount of groundwater would be used when CAP water flow is interrupted, the maximum drawdown of the Eloy Basin Aquifer after 30 years is predicted to be 4.3 feet at five feet from the center of pumping. Drawdown at ½, ¾ and 1 mile is projected as 0.33, 0.18 and 0.08 feet, respectively.

### Project Description

Sundance consists of up to twelve LM6000 SPRINT 45 MW combustion turbines. Currently, Sundance has constructed and operates only ten of these turbines because of transmission constraints that allow for only a generation of 450 MW.

At maximum hypothetical output and worst case ambient conditions, the Facility would require a maximum projected 1,650 acre-feet of raw water per year with 100% reliance on groundwater. Water is required as a coolant for the inlet air to the turbines and as an air pollutant control device to reduce Nitrogen oxide emissions using a water injection process. Water is initially delivered from the CAP project through local distribution canals of Hohokam Irrigation District, and collected in storage ponds. The water is then directed through a reverse osmosis process to lower the Total Dissolved Solids (TDS). The water is then purified through a demineralization process, and the treated water is consumptively used for turbine cooling and emissions reduction. The byproduct discharge water from the water treatment plant is then pumped to a retention pond. Although some of that discharge water will be allowed to evaporate, approximately 645 acre-feet per year will be available for re-use application to irrigate crops on adjoining Sundance farmland. The storage of post-process water is permitted under the State of Arizona Aquifer Protection Permit Number P-15327-23775-502451 issued May 29, 2002. The reuse of that water for irrigation is permitted under the State of Arizona Individual Permit for Direct Reuse of Industrial Wastewater Permit Number R23840.

Applicable state and federal permits limit the operation of the Facility to 6,500 hours per year with another 1,000 hours allowed for startup and shutdowns of the combustion turbines. The design of the water supply system is based on the Facility's projected maximum water consumption of approximately 1,650 acre-feet/year, calculated on a hypothetical continuous operation at maximum output up to the permit limit. Reserve capacity is designed into the system to ensure fire protection capability and to provide on-site regulatory storage adequate to provide primary source water, without groundwater backup, during periods of anticipated maintenance and repair on the CAP canal and other delivery system components.

### **Groundwater Potential Use**

No significant attributable impacts are anticipated, even if groundwater were to be used for a material portion of the Facility's needs, given the ability to offset groundwater use by reducing the historical agricultural pumping on the Sundance Property. The long history of substantial agricultural pumping at the Property and in the surrounding region, the increased local use of CAP water in lieu of groundwater, and the expected continuation of subsidized CAP agricultural water deliveries through the life of the Project support the conclusion that the Project would have no negative impacts on groundwater, and could have a nominal positive impact by reducing groundwater pumping from the Property.

Backup water will be supplied to the Facility from water wells on the Sundance Property. The maximum rate of the groundwater use projected for Sundance is less than 10 percent of the total use, or less than 165 acre-feet per year. As discussed above, groundwater would only be used during interruptions of CAP water due to maintenance or unscheduled events of a duration that would exhaust the substantial on-site water storage facilities.

### **Groundwater Model Results**

The operation of the groundwater wells would have a minimal effect on the Eloy Basin Aquifer. To determine the potential impact on the Eloy Basin aquifer, an analysis of the drawdown and cone of depression was performed based on the estimated maximum and minimum annual average water withdrawal rate for 30 years. The impact of pumping of the required maximum and minimum acre-feet per year from the Eloy Basin was modeled using a Theis-based spreadsheet model. This model is based on the equation for non-steady state flow of an isotropic, homogeneous, confined aquifer of infinite extent. The model assumed pumping using a well field of one well, with a continuous extraction of 118 gallons per minute maximum and 31 gallons per minute minimum for 30 years. The aquifer parameters utilized for the analyses were presented as part of the water resources description. Aquifer thickness was assumed as 100 feet based upon onsite drilling and studies by ADWR (ADWR, 1999). One well was simulated since the distance between the two extraction wells is nominal.

Results of the impact modeling indicate that after 30 years of at the maximum rate of 165 acre-feet per year, a cone of depression would be formed in the water table with a maximum drawdown of 4.28 feet at five feet from the center of pumping. Drawdown at  $\frac{1}{2}$ ,  $\frac{3}{4}$  and 1 mile is projected as 0.33, 0.18 and 0.08 feet, respectively.

Impact on the total volume of water in storage in the Eloy Valley aquifer is expected to be negligible. The Eloy Basin is within the Pinal Active Management Area (AMA). Aquifers in these areas are managed through detailed and extensive AMA management plans, with strict metering, reporting, and legally enforced pumping limitations. Subsidence from dewatering has occurred within the basin; however, the nominal amount of groundwater required for the Facility is not expected to cause subsidence in the area.

In summary, the physical impact of Sundance groundwater backup pumping of even 165 acre-feet per year would be a net positive in comparison to historical or future anticipated groundwater pumping from the Property wells for irrigation absent the Project. For example, in 1998, the farmer of the Property reported to ADWR pumping of over 250 acre-feet for irrigation. Prior to availability of subsidized regular CAP and "in lieu" CAP water, historical pumping for irrigation of the Property ranged around 1,000 acre-feet per year, and could continue at near such rates under the current AMA management plan and applicable water duty. The Facility utilizes CAP water, blended with reject stream water from the demineralization treatment process, for irrigation of Facility Site landscaping and ongoing agricultural operations on those portions of the Property not utilized by Sundance facilities. Groundwater pumping will be limited to the backup emergency supply for the Project. Thereby, the net impact on the aquifer, while negligible in any event at the quantities involved with this Project, will be a reduction of withdrawals, nominally enhancing the already rising water table, and will have no adverse impact on the aquifer or other groundwater pumpers.

# Griffith Energy Environmental Matrix

Item	Category	Respondant Value	Permitted Value	4	3	2	1
1	CO <sub>2</sub> (LBS/MWH)	855		0-500	500-1,000	1,000-2,000	>2,000
2	NO <sub>x</sub> (LBS/MWH)	0.12	0.08	0-1.0	1.0-5.0	5.0-10.0	>10.0
3	SO <sub>2</sub> (LBS/MWH)	0.004	0.02	0-1.0	1.0-5.0	5.0-10.0	>10.0
4	PM (LBS/MWH)	0.003	0.10	0-0.1	0.1-0.25	0.25-1.0	>1.0
5	CO (LBS/MWH)	0.16	0.11	0-0.25	0.25-0.5	0.5-1.0	>1.0
6	VOC (LBS/MWH)	0.007	0.03	0-0.025	0.025-0.05	0.05-0.1	>0.1
7	Hg (LBS/MWH)	0		0-0.005	0.005-0.01	0.01-0.1	>0.1
8	Water Consumption (GAL/MWH)	323		1-100	100-500	500-1,000	>1,000
9	Primary Water Source	Ground		Effluent	Surface	Ground	Other
10	Population (within 50 miles)	13,160		1-10,000	10,000-100,000	100,000-1,000,000	>1,000,000
11	Penalties (within last 5 years)	\$0		\$0-\$25,000	\$25,000-\$100,000	\$100,000-\$250,000	>\$250,000

## NOTES:

\* NOx and Co values include startups and shutdowns

Permit Limits for startup and shutdowns are:

NOX - 5.2 lb/min or 312 lb/hr for 5 hours maximum each startup period

CO - 124 lb/min or 7440 lb/hr for 5 hours maximum for each startup period

Startup and shutdown periods shall not exceed 1,200 hours per year per unit.

Based on operational permit limits, without starts and shutdowns, the lb/MWWhr values are:

100% Load (260 MW)

100% Load with duct firing (325 MW)

NO <sub>x</sub> (LBS/MWH)	0.08	NO <sub>x</sub> (LBS/MWH)	0.09
SO <sub>2</sub> (LBS/MWH)	0.02	SO <sub>2</sub> (LBS/MWH)	0.02
PM (LBS/MWH)	0.10	PM (LBS/MWH)	0.09
CO (LBS/MWH)	0.11	CO (LBS/MWH)	0.30
VOC (LBS/MWH)	0.03	VOC (LBS/MWH)	0.11

## Griffith Energy Air Quality Modeling Executive Summary

Dispersion modeling prepared for the Griffith Energy facility demonstrated that all air quality impacts would be well below all applicable federal and State of Arizona ambient air quality standards. A Prevention of Significant Deterioration (PSD) construction permit, Title V operating permit, and Title IV Acid Rain permit were issued by the Arizona Department of Environmental Quality (ADEQ) on August 13, 1999 as Permit #1000940. Griffith Energy became operational in January 2002. This summary presents the Best Available Control Technology (BACT) emission limits approved by the ADEQ and the results of air dispersion modeling submitted with the permit application.

### Facility Description

The Griffith Energy facility is permitted as a nominal 520 MW natural gas fired simple cycle power generation facility. Supplemental duct firing increases the maximum facility output to 600 MW. The primary processes consist of the following equipment:

- 2 General Electric 7FA combustion turbine generator units (CTGs) or with dry Low NO<sub>x</sub> combustors
- 2 heat recovery steam generators (HRSGs) with supplemental firing
- 1 steam turbine generator unit
- cooling tower for the steam turbine condenser and equipment cooling

### BACT Permit Limits

Table 1 shows the BACT emission limits for the Griffith Energy facility.

Table 1 Sundance Energy Emission Limits			
Pollutant	Control Technology	BACT Limit <sup>1</sup>	Averaging period
Nitrogen Oxide (NO <sub>x</sub> )	Selective Catalytic Reduction and dry low NO <sub>x</sub> burners	3.0 ppmvd	3-hour
Carbon Monoxide (CO)	Good Combustion Practice	10.0 ppmvd at 100% load; 20 ppmvd at 100% load with duct firing	3-hour
Fine Particulates (PM <sub>10</sub> )	Use of pipeline quality natural gas	17.8 lbs/hr at 100% load; 28.2 lb/hr at 100% load with duct	3-hour

		firing	
Fine Particulates from Cooling Tower (PM <sub>10</sub> )	0.003% drift eliminators	5.9 lb/hr	NA
Volatile Organic Compounds (VOC)	Good Combustion Practice	7.4 lbs/hr at 100% load; 35.2 lb/hr at 100% load with duct firing	3-hour
Sulfur Dioxide (SO <sub>2</sub> )	Use of pipeline quality natural gas	4.2 lbs/hr at 100% load; 5.7 lb/hr at 100% load with duct firing	3-hour

<sup>1</sup> ppmvd: parts per million at 15% O<sub>2</sub>

### PSD Dispersion Modeling

Compliance with air quality standards was determined using dispersion modeling approved by ADEQ. Emissions were calculated based upon the BACT limits identified in the permit process. The Industrial Source Complex Short Term (ISCST3) dispersion model was used for the ambient impact analyses. The ISCST3 model is a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground-level elevations can exceed the stack heights of the emission sources. The modeling results of all applicable pollutant ambient air concentrations for their respective averaging periods were compared against the Arizona Ambient Air Quality Standards (AAAQS) and the PSD Class II increment consumption.

Receptors (geographical points to evaluate pollutant concentrations) were set at 25-meter intervals around the property boundary. Outside the property boundary, receptors were set at 100-meter intervals to one kilometer, and 300-meter intervals from one to 20 kilometers.

The results of the modeling, shown in Table 2, demonstrated that the Griffith Energy facility will be in compliance with all applicable federal and state air quality laws, regulations and standards.

**Table 2**  
**Griffith Energy Predicted Maximum Air Quality Impacts**

Pollutant	Averaging Period	Maximum Concentration (µg/m <sup>3</sup> )	Percent of Arizona Ambient Air Quality Standard	Percent of Class II Increment
NO <sub>2</sub>	Annual	10.42	10.4	41
SO <sub>2</sub>	3 hour	8.0	0.6	1.6

	24 hour	3.9	1.1	4.3
	Annual	0.4	0.5	2.1
CO	1 hour	561	1.4	NA
	8 hour	100	1.0	NA
PM <sub>10</sub>	24 hour	19.2	11.7	58.5
	Annual	1.7	3.2	9.3
Formaldehyde	1 hour	1.9	3.8	NA
	24 hour	0.4	1.7	NA
	Annual	0.02	32.5	NA

#### Federal Class I Areas

Potential impacts to air quality and air quality related values (AQRV) were evaluated for Class I airsheds located within 100 kilometers of the Griffith Energy facility. The closest boundary of the Grand Canyon National Park is approximately 90 kilometers north-northeast. The Class I area analysis was completed using the EPA-approved CALPUFF dispersion and atmospheric chemical transformation model. The Class I impact analysis was reviewed and approved by the Grand Canyon National Park federal land managers. The results of the analysis demonstrated that potential effects to visibility and acid deposition at the Grand Canyon would be below the significance levels established by the federal land manager.

## **Griffith Energy Groundwater Modeling Executive Summary**

Groundwater modeling was conducted to estimate the groundwater withdrawal and drawdown in the Golden Valley sub-basin south of Kingman, Arizona as a result of projected water usage for the Griffith Energy facility, modeled in conjunction with continued pumping of water by the domestic users in the Golden Valley area. The modeling analysis estimated that the groundwater drawdown at the end of 40 years of withdrawal would be 89 feet in the two modeled wells in Golden Valley and 129 feet in the six wells in the Griffith well field. The drawdown would be 43 feet at a radius of 2,000 feet from the wells in Golden Valley and 67 feet at a radius of 2,000 feet from the corner of the Griffith source well field.

### **Project Description**

Griffith Energy is a baseload 520 megawatt (MW), natural gas-fired combined cycle power plant with a peaking capacity of 600 MW when supplemental duct firing is employed. Plant facilities include two General Electric 7FA combustion turbines, two heat recovery steam generators with duct burners, one steam turbine generator, a mechanical wet cooling tower, a chiller cooler tower, and other ancillary equipment. Water is required to 1) generate steam to warm up and drive the steam turbine generator; 2) condense steam exhausted from the steam turbine; 3) cool the plant machinery; and 4) supply potable water for human consumption, waste disposal, and facility maintenance. Griffith Energy contracts with the Golden Valley Improvement District No. 2 (GVID2) to provide up to 3,300 gallons per minute (gpm) of groundwater (3,000 to 5,000 acre-feet per year) from the Sacramento Valley Basin aquifer. GVID2 has drilled six new wells about three miles west of the site. These have been drilled to depths of approximately 1,000 feet and produce approximately 1,000 gpm per well.

The Griffith Energy facility produces process wastewater at various stages of the power generation cycle. The wastewater passes through a series of on-site systems that collect, treat, store and dispose of wastewater originating in the plant. Griffith Energy is a zero-discharge facility. All wastewater is collected and then stored in a 25-acre evaporation pond. The pond is permitted under the State of Arizona Aquifer Protection Permit Program.

### **Modeling Methodology**

The program THWells Version 4.01 was utilized to estimate the drawdown caused by the water withdrawal from Golden Valley proposed by Griffith Energy. Drawdowns resulting from groundwater withdrawal have been projected for the worst case (maximum consumption) conditions to conservatively estimate the effect of withdrawal.

## **Modeling Inputs**

For the purpose of this analysis, a constant withdrawal figure of 2,235 acre-feet per year (projected population of 20,998 in the year 2040 times 95 gallons per person per day for a total withdrawal of 89,400 acre-feet over 40 years) was used as the domestic demand for Golden Valley in the calculations. This demand for domestic water is conservative since it utilizes maximum withdrawal over the entire 40-year period.

The maximum hypothetical withdrawal (full time at the 3,300 gpm peak demand) for use by the Griffith Energy Project is 5,323 acre-feet per annum. This is assumed to start in the year 2000 and ends in the year 2040 for a total withdrawal of 212,920 acre-feet over the projected 40-year life of the plant. A more realistic withdrawal figure for Griffith is the projected average use of 3,064 acre-feet per annum (using 1,900 gallons per minute average demand) for a total withdrawal of 122,560 acre-feet over the projected 40 year life of the plant. However, as stated earlier, this most conservative case analysis uses the maximum figure of withdrawal, 212,920 acre-feet. The point of withdrawal for the 5,323 acre-feet per annum is approximately in the middle of the Golden Valley sub-basin.

## **Modeling Results**

The projected drawdowns at the end of 40 years of withdrawal are 89 feet in the two wells in Golden Valley and 129 feet in the six wells in the Griffith well field. The projected drawdown is 43 feet at a radius of 2,000 feet from the wells in Golden Valley and 67 feet at a radius of 2,000 feet from the corner of the GVID/Griffith well field.

## **XI. Site/Facility Requirements for Proposed Generating Facilities**

### **A. Commercial Operation Date**

Projected construction (mechanically complete) end date: April 15, 2006

Projected start up and testing completion date: May 30, 2006

Projected commercial operation date: May 31, 2006

### **B. Projected Schedule for Acquisition of Necessary Transmission and Interconnection Service**

WMGF has filed both an interconnection request and a request for firm transmission service with Western. As a result of these requests, Western has performed two SIS's which identified the proposed Project interconnection points and assessed system impacts due to the addition of the Project. In addition, Western is finalizing a Facility Study (FS) for the Project. APS has reviewed and concurred with the results of the SISs and has provided input into the FS. Pursuant to the SISs and the FS, the Project will be interconnected with the Western system at its Wellton-Mohawk Ligurta Substation, a new 161-kV line will be built between Ligurta and North Gila, a 161/69-kV transformer will be installed at North Gila (providing another interconnection point between the Western and APS systems), and Western's Ligurta-Gila 161-kV line will be rebuilt to increase its capacity. The Project will shortly initiate activities with Western to finalize the required agreements providing for the interconnection of the Project and for firm transmission service between the Project and the Western/APS interconnection points in the Yuma area. It is anticipated that these agreements will be in place within the next six to eight months with service to commence upon start up and testing of the Project.

### **C. Product Commitment**

The Project does not offer any product commitments other than those specifically set forth in WMGF's proposal.

### **D. ACC Access**

Project will allow access to the physical plant site for the Arizona Corporation Commission (ACC) staff inspection pursuant to ACC Decision No. 65743, dated March 14, 2003.

### **E. Environmental Information**

The minimum environmental requirements as set forth in Exhibit C of the RFP as are follows:

1. The affected population residing within census tracts located within a 50 mile radius of the Project, as provided by the 2000 Census, is 184,439. This value demonstrates the

maximum potentially affected population (as the population for entire tracts, even if only a portion of the tract is included within the 50 mile radius, was used for the cumulative analysis).

Neither of the affiliated companies has generating facilities in Arizona and those facilities outside of the state have not been assessed any environmental fines in the past five years.

2. Air pollutant dispersion analyses were performed for the Air Quality Permit Application for the WMGF. The dispersion modeling demonstrated that air quality effects from the WMGF would be well below all relevant State of Arizona and federal air quality standards. Also, the analysis of Best Available Control Technology (BACT) performed for the Project verifies that state-of-the-art control technology will be applied to ensure that the WMGF operates at the lowest economically achievable emission rates for facilities of this type.

The proposed WMGF emission rates as negotiated with the Arizona Department of Environmental Quality (ADEQ) in connection with the Air Quality Permit Application, as recently as April 2003, is summarized in **Table E-1** below. The combustion turbines (CT) emissions in this table represent emissions for each combustion turbine at steady state operating conditions.

**TABLE E-1  
WMGF EMISSION SUMMARY**

Source	Pollutant	Control Technology	Emission Level
<b>Combustion Turbines</b>	NO <sub>x</sub>	DLN with SCR	W 501F 2.5 ppm <sup>1</sup> , 22.8 lb/hr GE 7FA 2.5 ppm, 20.0 lb/hr Maybe reduced to 2.0 ppmvd at 15% O <sub>2</sub> , 1-hour average emission limit after the first two years of operation.
	CO	CT design, proper combustion, oxidation catalyst	W 501F 3.0 ppm, 16.7 lb/hr GE 7FA 3.0 ppm, 14.6 lb/hr 3-hour average
	VOC	CT design, combustion control, oxidation catalyst	W 501F 3.0 ppm, 9.5 lb/hr GE 7FA 3.0 ppm, 8.3 lb/hr 3-hour average
	SO <sub>2</sub>	Low sulfur gas	W 501F 5.3 lb/hr GE 7FA 4.7 lb/hr
	PM <sub>10</sub>	Low sulfur gas	W 501F 32.9 lb/hr GE 7FA 29.7 lb/hr
<b>Auxiliary Boiler</b>	NO <sub>x</sub> , CO, VOC, SO <sub>2</sub> , PM <sub>10</sub>	Low NO <sub>x</sub> burner and good combustion practices	NO <sub>x</sub> = 13.9 lb/hr CO = 2.9 lb/hr VOC = 0.13 lb/hr PM <sub>10</sub> = 0.13 lb/hr SO <sub>2</sub> = 0.04 lb/hr
<b>Emergency Fire Pump</b>	NO <sub>x</sub> , CO, VOC, SO <sub>2</sub> , PM <sub>10</sub>	Good combustion practices, inlet air filter, limit operation to 200 hrs/yr	NO <sub>x</sub> = 7.45 lb/hr CO = 0.65 lb/hr VOC = 0.64 lb/hr PM <sub>10</sub> = 0.053 lb/hr SO <sub>2</sub> = 0.10 lb/hr
<b>Black Start Generators</b>	NO <sub>x</sub> , CO, VOC, SO <sub>2</sub> , PM <sub>10</sub>	DLN, good combustion practices, limit operation to 200 hrs/yr,	NO <sub>x</sub> = 20.2 lb/hr CO = 40.1 lb/hr VOC = 6.5 lb/hr PM <sub>10</sub> = 5.3 lb/hr SO <sub>2</sub> = 0.12 lb/hr
<b>Cooling Tower</b>	PM <sub>10</sub>	High Efficiency Drift Eliminators	3.0 lb/hr

<sup>1</sup> Parts per million dry volume basic corrected to 15 percent oxygen

### Applicable Air Quality Standards

The following air quality assessments were included in these analyses:

- Arizona Ambient Air Quality Standards (AAAQS),
- Prevention of Significant Deterioration (PSD) increment consumption, and
- Arizona Ambient Air Quality Guidelines (AAAQG) for hazardous air pollutants (HAPs).

Also, visibility and deposition impacts were evaluated for Joshua Tree National Park. This Class I area is located approximately 100 miles west-northwest of the facility.

As stated above, the results of these analyses demonstrated that the WMGF would comply with all federal and state air quality criteria and standards.

### Modeling Summary

Air pollutant dispersion modeling was performed using ADEQ and U.S. Environmental Protection Agency (EPA) approved methods. This modeling included consultation with ADEQ to ensure that approved methods and data were employed in the analyses.

### Methodology

The dispersion modeling evaluated the full range of output for the maximum operating scenario. The Industrial Source Complex air pollutant dispersion model with Plume Rise Model Enhancements (ISC3-PRIME) model was used for the AAAQS, PSD, and AAAQG analyses. This model provides improved calculations for exhaust plumes that are influenced by turbulence generated by nearby buildings.

Five years of hourly meteorological data (1987 – 1991), and 4,533 model receptors were included in the AAAQS, PSD, and AAAQG modeling analyses.

The AAAQS analysis for all combustion sources included emissions of nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), non-methane-ethane volatile organic compounds (VOC), particulate matter with a nominal aerodynamic diameter of less than 10 micrometers (PM<sub>10</sub>), and sulfur dioxide (SO<sub>2</sub>). Cooling tower emissions of PM<sub>10</sub> were also included in the modeling.

This analysis also included emissions from the APS Yucca Power Plant and Yuma Cogeneration Associates as well as criteria pollutant background concentration data that were provided by ADEQ.

The PSD analysis included all the WMGF sources as well as NO<sub>x</sub> and PM<sub>10</sub> increment expanding and consuming emissions from Interstate 8 (I-8) vehicle tailpipe emissions.

The AAAQG analysis for all the WMGF combustion sources evaluated all potential HAP emissions that are regulated under these guidelines including formaldehyde and benzene.

The modeling evaluated CT emissions over the expected range of operating loads, local ambient temperatures, and local relative humidity. Conservative schedules for CT startup and shutdown emissions were also included in this evaluation.

### Modeling Results

#### The AAAQS Analysis

Tables E-2 and E-3 present the results of the WMGF AAAQS analysis. Table E-2 presents the estimated ambient impacts from the WMGF. Table E-3 presents the cumulative impacts from the WMGF as well as from the other two power plants. These results show that, using conservative operating scenarios, no regulatory ambient air quality criteria would be exceeded. The ambient impact values in these tables represent the maximum impacts.

**TABLE E-2**  
**MODELED WMGF MAXIMUM AMBIENT AIR IMPACTS**

Pollutant	Period	AAAQS ( $\mu\text{g}/\text{m}^3$ )	Background ( $\mu\text{g}/\text{m}^3$ )	WMGF Impact ( $\mu\text{g}/\text{m}^3$ )	WMGF Impact with Background ( $\mu\text{g}/\text{m}^3$ )	Relative to AAAQS (%)
NO <sub>2</sub>	Annual	100	4	1.4	5.4	5.4%
CO	1 hour	40000	582	1331.2	1913.2	4.8%
	8 hour	10000	582	300.0	882.0	8.8%
PM <sub>10</sub>	24 hour	150	114	8.9	122.9	81.9%
	Annual	50	39	1.7	40.7	81.4%
SO <sub>2</sub>	3 hour	1300	246	8.6	254.6	19.6%
	24 hour	365	45	1.0	46.0	12.6%
	Annual	80	6	0.2	6.2	7.8%

$\mu\text{m}/\text{m}^3$  = micrograms per cubic meter

**TABLE E-3**  
**MODELED CUMULATIVE MAXIMUM AMBIENT AIR IMPACTS**

Pollutant	Period	AAQs ( $\mu\text{g}/\text{m}^3$ )	Background ( $\mu\text{g}/\text{m}^3$ )	Cumulative Impact ( $\mu\text{g}/\text{m}^3$ )	Cumulative Impact with Background ( $\mu\text{g}/\text{m}^3$ )	Relative to AAQs (%)
NO <sub>2</sub>	Annual	100	4	4.0	8.0	8.0%
CO	1 hour	40000	582	1331.2	1913.2	4.8%
	8 hour	10000	582	300.0	882.0	8.8%
PM <sub>10</sub>	24 hour	150	114	8.9	122.9	81.9%
	Annual	50	39	1.8	40.8	81.7%
SO <sub>2</sub>	3 hour	1300	246	81.5	327.5	25.2%
	24 hour	365	45	18.8	63.8	17.5%
	Annual	80	6	2.4	8.4	10.5%

$\mu\text{m}/\text{m}^3$  = micrograms per cubic meter

#### PSD Class II Increment Analysis

The PSD Class II Area increment consumption analysis showed that only a fraction of the local increment would be consumed. **Tables E-4 and E-5** present the results of this analysis. The increment impact values in the tables represent the maximum impacts. The low NO<sub>2</sub> impact on **Table E-5** resulted from a decrease of I-8 tailpipe NOx emissions (increment expansion) since the minor source increment baseline (1991).

**TABLE E-4**  
**MODELED MAXIMUM CLASS II INCREMENT CONSUMPTION**  
**WMGF SOURCES**

Pollutant	Period	Increment ( $\mu\text{g}/\text{m}^3$ )	WMGF Impact ( $\mu\text{g}/\text{m}^3$ )	Relative to Increment (%)
NO <sub>2</sub>	Annual	25	1.4	5.4%
PM <sub>10</sub>	24 hour	30	8.9	29.6%
	Annual	17	1.7	10.0%
SO <sub>2</sub>	3 hour	512	8.6	1.7%
	24 hour	91	1.0	1.1%

**TABLE E-5**  
**MODELED MAXIMUM CLASS II INCREMENT CONSUMPTION**  
**ALL SOURCES**

Pollutant	Period	Increment ( $\mu\text{g}/\text{m}^3$ )	Cumulative Impact ( $\mu\text{g}/\text{m}^3$ )	Relative to Increment (%)
NO <sub>2</sub>	Annual	25	0.009	0.0%
PM <sub>10</sub>	24 hour	30	8.9	29.6%
	Annual	17	1.8	10.6%
SO <sub>2</sub>	3 hour	512	8.6	1.7%
	24 hour	91	1.0	1.1%

#### PSD Class I Increment Analysis

Ambient air impacts at Joshua Tree National Monument were estimated to be well below the Class I increment. These impacts are related to emissions from WMGF sources. Table E-6 presents the results of the Class I increment analysis. These impacts were estimated using the CALPUFF air pollutant dispersion model and the same 5 years of meteorological data that were used in the Class I visibility impact analysis (1986 – 1990).

**TABLE E-6**  
**MODELED MAXIMUM CLASS I INCREMENT CONSUMPTION**

Pollutant	Period	Increment ( $\mu\text{g}/\text{m}^3$ )	Cumulative Impact ( $\mu\text{g}/\text{m}^3$ )	Relative to Increment (%)
NO <sub>2</sub>	Annual	2.5	0.0105	0.4%
PM <sub>10</sub>	24 hour	8	0.1050	1.3%
	Annual	4	0.0123	0.4%
SO <sub>2</sub>	3 hour	25	0.0636	0.3%
	24 hour	5	0.0137	0.3%
		2	0.0015	0.1%

#### AAAQG Pollutants Analysis

The results of the AAAQG analysis showed that no ambient HAP guideline would be exceeded. Table E-7 presents the results of this analysis. The ambient impact values in this table represent the maximum impacts.

**TABLE E-7**  
**MODELED MAXIMUM AMBIENT AIR HAP IMPACTS**

HAP	1-Hour Facility Impact ( $\mu\text{g}/\text{m}^3$ )	1-Hour AAAQG ( $\mu\text{g}/\text{m}^3$ )	24-Hour Facility Impact ( $\mu\text{g}/\text{m}^3$ )	24-Hour AAAQG ( $\mu\text{g}/\text{m}^3$ )	Annual Facility Impact ( $\mu\text{g}/\text{m}^3$ )	Annual AAAQG ( $\mu\text{g}/\text{m}^3$ )
1,3-Butadiene	1.70E-01	7.20E+00	1.23E-02	1.90E+00	1.21E-04	6.70E-02
Acetaldehyde	7.28E-01	2.30E+03	5.38E-02	1.40E+03	3.80E-03	5.00E-01
Acrolein	6.74E-01	6.70E+00	4.90E-02	2.00E+00	8.57E-04	
Ammonia	3.62E+01	2.30E+02	6.29E+00	1.40E+02	1.49E+00	
Benzene	4.18E-01	6.30E+02	2.99E-02	5.10E+01	1.26E-03	1.40E-01
Ethylbenzene	6.93E-02	4.50E+03	1.20E-02	3.50E+03	2.79E-03	
Formaldehyde	5.26E+00	2.00E+01	5.07E-01	1.20E+01	6.53E-02	8.00E-02
Naphthalene	2.61E-02	6.30E+02	1.89E-03	4.00E+02	1.24E-04	
PAH (as Benzo(a)pyrene)	3.62E-02	6.70E-01	2.72E-03	1.80E-01	2.08E-04	4.80E-04
Propylene Oxide	6.16E-02	1.50E+03	1.07E-02	4.00E+02	2.53E-03	2.00E+00
Toluene	3.21E-01	4.70E+03	5.23E-02	3.00E+03	1.14E-02	
Xylene (Total)	1.50E-01	5.50E+03	2.50E-02	3.50E+03	5.60E-03	

PAH = Polynuclear aromatic hydrocarbon

### Class I Visibility Impacts

The CALPUFF dispersion model, which also accounts for atmospheric chemical reactions, was used to assess both visibility and deposition impacts at Joshua Tree National Park. Table E-7 lists the highest percent change in extinction (visibility) for each of the 5 meteorological years. The highest 24-hour decrease in visibility is predicted to be 3.82 percent. Therefore, the changes in extinction at Joshua Tree National Park are predicted to be less than the significant impact guideline value of 5 percent for any 24-hour period (as prescribed by the Federal Land Managers).

**TABLE E-7**  
**CLASS I VISIBILITY IMPACT AT**  
**JOSHUA TREE NATIONAL PARK**

Modeled Year	Change in Extinction (percent)
1986	3.56
1987	3.29
1988	3.69
1989	2.96
1990	3.82

### Class I Deposition Impacts

Table E-8 presents the maximum estimated modeled values for total nitrogen and sulfur deposition at Joshua Tree National Park. These values are expressed as the mass (kilograms) of each element to be deposited over a hectare on an annual basis (kg/ha-yr). Total nitrogen includes all nitrates, and total sulfur includes all sulfates. These impacts were estimated using CALPUFF and the same 5 years of meteorological data that were

used in the visibility analysis. These values are well below the regulatory criteria for this area (5 kg/ha-yr, as prescribed by the Federal Land Managers).

**TABLE E-8 CLASS I DEPOSITION IMPACT  
AT  
JOSHUA TREE NATIONAL PARK**

<b>Pollutant</b>	<b>Annual Deposition (kg/ha-yr)</b>
Total Nitrogen	0.003
Total Sulfur	0.0003

3. The WMGF will not utilize groundwater for its operations. Thus adjacent wells will not be impacted by the operation of WMGF. Instead the WMGF will utilize the adjacent Wellton-Mohawk Canal (WMC) surface water. The Wellton-Mohawk Irrigation and Drainage District (WMIDD) will provide and deliver, via the WMC, all of the water requirements for the Project, which is allocated and allowed by existing permits. Therefore, no surface or groundwater modeling was required. The Project is estimated to use a maximum of 1,678 acre-feet of water annually.

A water treatment facility to maximize water conservation efforts will be incorporated with operation of the Project. Although construction activities may remove existing vegetation and potentially promote erosion and sedimentation into local washes, the use of erosion control measures and the absence of perennial streams in vicinity of the Project site will minimize the effects of disturbed soils on water quality. Stormwater runoff, and/or site drainage facilities, will be routed to catchments using diversion dikes, in accordance with the Yuma County Flood Control District, to prevent the discharge from leaving the site. These detention facilities will regulate post-development stormwater flow rate to not exceed the predevelopment rate, thereby preserving the integrity of existing and natural drainage patterns.

Effluent wastewater from Project operations, if not suitable for reuse, should be minimal and disposed of in an evaporation pond designed and constructed in accordance with Best Available Demonstrated Control Technology (BACDT) or treated and recycled back into the process. The evaporation pond will be permitted through the ADEQ's Aquifer Protection Permit (APP) Program to ensure that aquifer water quality standards are not compromised. Mineral salts will be disposed of in an appropriate landfill.

A potable water treatment system will be incorporated in the Project to treat water from the WMC for domestic use. A potable water storage tank will be incorporated into the site plan.

A septic system tank and two leach lines, 15 feet apart, will be constructed on Site. The permit will be submitted to Yuma County as the Special Use Permit for the WMGF Site has already been approved.

4. WMGF has prepared copies of all documents and/or supplemental information associated with the air quality modeling as described in item 2 and this information is available upon request.

### Environmental Matrix for Bidders

<u>Item</u>	<u>Category</u>	<u>Respondent Value</u>	<u>4</u>	<u>3</u>	<u>2</u>	<u>1</u>
1 CO <sub>2</sub> (lb/MWH)	3	679	0-500	500-1,000	1,000-2,000	>2,000
2 NO <sub>x</sub> (lb/MWH)	4	0.07	0-1.0	1.0-5.0	5.0-10.0	>10.0
3 SO <sub>2</sub> (lb/MWH)	4	0.01	0-1.0	1.0-5.0	5.0-10.0	>10.0
4 PM (lb/MWH)	4	0.10	0-0.1	0.1-0.25	0.25-0.50	>0.50
5 CO (lb/MWH)	4	0.05	0-0.25	0.25-0.50	0.50-1.0	>1.0
6 VOC (lb/MWH)	4	0.025	0-0.025	0.025-0.050	0.050-0.100	>0.100
7 Hg (lb/GWH)	4	0	0-0.005	0.005-0.010	0.010-0.100	>0.100
8 Water Consumption (gal/MWH)	3	230	0-100	100-500	500-1,000	>1,000
9 Primary Water Source	3	Surface <i>See Note 1</i>	Effluent	Surface	Ground	Other
10 Population (within 50 miles)	2	184,439 <i>See Note 2</i>	0-10,000	10,000-100,000	100,000-1,000,000	>1,000,000
11 Penalties (within last 5 years)	4	0 <i>See Note 3</i>	\$0-\$25,000	\$25,000-\$100,000	\$100,000-\$250,000	>\$250,000

**Notes:**

- 1) Water for the Project is provided by WMIDD's irrigation canals and it has perpetual rights to the water in sufficient quantities.
- 2) Maximum potentially affected population totals for each census tract within 50 miles radius were used. This value also excludes any population in Mexico which is included in the 50 mile radius.
- 3) Jasper Energy and Primesouth facilities have had no fines in the past five years.

**F. Adequate Fuel and Transport**

The WMGF has carefully examined fuel supply and transportation options, and from the outset, WMGF has included fuel procurement as a key component of its development efforts. WMGF has prepared and filed before the Arizona Power Plant and Transmission Line Siting Committee, a Natural Gas Acquisition Plan in which it outlined in detail the natural gas supply and transportation blueprint it intends to follow, addressing this critical issue. A copy of the Natural Gas Acquisition Plan is attached as Appendix B. WMGF will continue to monitor developments and initiate further discussions with multiple potential counter parties in the fuels and transport area as development continues.

Exhibit B**ENVIRONMENTAL INFORMATION****Blythe Facility**

1. Blythe permitted emissions limits [lb/hr, lb/day, tons/year]:
  - NO<sub>x</sub> - 19.80 lb/hr, 5,762 lb/day, 202 tons/year, verified by CEMS
  - CO - 35.20 lb/hr, 3,808 lbs/day, 306 tons/year
  - VOC as CH<sub>4</sub> - 2.9 lb/hr, 239 lb/day, 24 tons/yr, verified by compliance tests and hours of operation in mode
  - SO<sub>x</sub> as SO<sub>2</sub> - 2.7 lb/hr, 130 lb/day, 24 tons/year, verified by fuel sulfur content and fuel use data
  - PM<sub>10</sub> - 11.5 lb/hr, 565 lb/hr, 103 tons/year, verified by CEMS

Based on the 2000 Census, the affected population is approximately 12,000 persons living in the City of Blythe. The project is not currently in commercial operation so there has been no potential for excursions from the permitted limits.

2. The Blythe project was subject to CA Energy Commission, Environmental Protection Agency, and Mojave Desert Air Quality Management District air emissions modeling requirements. The project has installed Best Available Control Technology (BACT) and purchased the necessary Emission Reduction Credits (ERCs) to offset NO<sub>x</sub>, CO and PM<sub>10</sub> emissions.
3. As a part of the CA Energy Commission Application for Certification a 40-year aquifer impact analysis was conducted for the project. The project is licensed to use 3,300 acre-feet of water per year for the life of the project. At maximum load this project will not exceed this water use. Aquifer testing to demonstrate compliance with the license is ongoing.
4. Air emissions and water use modeling information is contained in the CA Energy Commission Application for Certification and is available to APS upon request.
5. Exhibit C per RFP

**Environmental Matrix for Bidders**

<u>Item</u>	<u>Category</u>	<u>Value</u>
1	CO <sub>2</sub> (lb/MWH)	3
2	NO <sub>x</sub> (lb/MWH)	4
3	SO <sub>2</sub> (lb/MWH)	4
4	PM(lb/MWH)	4
5	CO(lb/MWH)	4
6	VOC(lb/MWH)	4
7	Hg (lb/GWH)	4
8	Water Consumption (gal/MWH)	3
9	Primary Water Source	2
10	Population (within 50 miles)	3
11	Penalties (within las 5 years)	4



**Shell Trading**

**ATTACHMENT A**

<b>Unit</b>	<b>La Rosita Facility</b>
<b>Location</b>	<b>Mexicali, Mexico</b>
<b>Delivery Point</b>	<b>Imperial Valley Substation</b>
<b>FERC Authority</b>	<b>Coral Power LLC maintains a FERC certification authorizing Coral Power LLC to sell power at market based rates and is a tolling counterparty to La Rosita I. The FERC certification is available upon request.</b>
<b>Environmental</b>	<b>The units proposed for in this response will have SCR catalyst to reduce NOx emissions.</b>

**Following will be provided as part of pricing**

**Availability factor**

**Number of starts and costs**

**Variable O&M**



**ATTACHMENT B**

**Unit** Harquahala Generating Station

**Location** Maricopa County, AZ; 60 miles west of Phoenix

**Delivery Point** Hassayampa Substation – Palo Verde

**FERC Authority** Harquahala Generating Company, in docket ER01-748-000, received is FERC license to sell at market based rates.

**Environmental**

Item	Category	Value
CO2 (lb/MWh)	3	782
NOx (lb/MWh)	4	0.071
SO2 (lb/MWh)	4	0.016
PM (lb/MWh)	4	0.068
CO (lb/MWh)	4	0.104
Hg (lb/MWh)	4	0.022
VOC	3	0.002
Water Consumption (gal/MWh)	3	200
Primary Water Source	3	Surface
Population within 50 miles	2	368,460
Penalties within last 5 years	4	\$0

Following will be provided as part of pricing

Availability factor

Number of starts and costs

Variable O&M

***Harquahala Generating Company, LLC***

April 3, 2003

2530 N 491<sup>st</sup> Avenue  
POB 727  
Tonopah, AZ 85354

928.372.2240  
Fax: 928.372.4762

**APPENDIX D: ENVIRONMENTAL SUMMARY INFORMATION**



**PACE** |

Global Energy Services

4401 Fair Lakes Court, Suite 400  
Fairfax, Virginia 22033-3848 USA  
Phone: 703-818-9100  
Fax: 703-818-9108

## Harquahala Track B Emissions

Prepared for:

April 1, 2003

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## Response to Exhibit C: Environmental Information

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### ENVIRONMENTAL MATRIX FOR BIDDERS

Table 1: Environmental Matrix for Bidders

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	Item	Category	Value
1	CO2 (lb/MWh)	3	782
2	NOx (lb/MWh)	4	0.071
3	SO2 (lb/MWh)	4	0.016
4	PM (lb/MWh)	4	0.068
5	CO (lb/MWh)	4	0.104
6	VOC (lb/MWh)	4	0.022
7	Hg (lb/GWh)	4	0.002
8	Water Consumption (gal/MWh)	3	200
9	Primary Water Source	3	Surface
10	Population within 50 miles	2	368,460
11	Penalties within last 5 years	4	\$0

As the Facility is new and has not yet begun commercial operation, there is no operating environmental data to provide.



## **EXECUTIVE SUMMARY AND RESULTS OF AIR QUALITY IMPACT MODELING**

Air quality modeling analyses were performed for the Harquahala Generating Project (HGP) as part of the Prevention of Significant Deterioration (PSD) and Title V permit application process with Maricopa County Environmental Services Department (MCESD). Based on the analyses below, the modeled impacts from operational emissions, when combined with existing background pollutant levels, would not exceed national or state Ambient Air Quality Standards (AAQS). Predicted concentrations for NO<sub>2</sub>, CO, PM<sub>10</sub>, and SO<sub>2</sub> are below PSD significance criteria. (Tables 1 and 2 show the national and state AAQS, as well as the PSD significance levels.) Therefore, it was not necessary to perform increment consumption analyses. Emissions of NO<sub>x</sub>, an ozone precursor, would not impact the Phoenix Metro Ozone Non-Attainment area. Impacts on soils, vegetation and visibility/regional haze in Class I areas are also less than significant. HGP will not significantly increase local permanent employment (approximately 35 full-time employees), and will not induce significant secondary industrial or residential growth. Therefore, HGP is not expected to have any significant impact on growth in the region.

### **AMBIENT AIR QUALITY MODELING**

The evaluation of air quality impacts consists primarily of air dispersion modeling to assess offsite concentrations of air contaminants from HGP in comparison to the AAQS and significance thresholds. Modeling was conducted using EPA-approved dispersion models to calculate potential impacts from operational emissions from pollutants that classified the HGP as a major source. HGP's potential to emit exceeds major stationary source PSD thresholds and significant emission levels for NO<sub>x</sub>, CO, and PM<sub>10</sub>. Significant emission levels are also exceeded for SO<sub>2</sub> and VOC. Emissions include combustion pollutants from the natural gas-fired turbines, an emergency generator and a diesel firewater pump, and PM<sub>10</sub> emissions from the cooling tower. [Note: all emission information is provided in HGP submittals for the PSD and Title V Permit Application (final revised permit application submitted to MCESD August 29, 2000; additional modifications on file with MCESD).] In accordance with the MCESD guidelines, ozone formation was not modeled.

Air Quality Related Values (AQRV) analyses were performed to address potential impacts on soil, vegetation, and visibility in Class I areas. These analyses are required pursuant to PSD regulations and were performed in accordance with discussions with both the National Park Service (NPS) and the United States Forest Service (USFS). As requested by the USFS, analyses for visibility and nitrate and sulfate deposition were also performed for selected Class II Wilderness Areas near HGP. These analyses are further discussed in the Executive Summary and Results of Air Quality Impact Modeling.

The air dispersion models that were used in these analyses are described in the following sections. All analysis methodologies were current at the time they were conducted and analysis protocols were accepted by the agencies involved.



Table 2: Summary Of Federal And Arizona State Ambient Air Quality Standards

Pollutant	Averaging Time	Significant Impact Levels	Standards <sup>1</sup>	
			Primary <sup>(2,3)</sup>	Secondary <sup>(2,4)</sup>
Oxidant (ozone)	1-hour	None	0.12 ppm (235 $\mu\text{g}/\text{m}^3$ )	Same
Carbon monoxide	8-hour	500 $\mu\text{g}/\text{m}^3$	9 ppm (10 $\text{mg}/\text{m}^3$ )	Same
	1-hour	2,000 $\mu\text{g}/\text{m}^3$	35 ppm (40 $\text{mg}/\text{m}^3$ )	Same
Nitrogen dioxide	Annual average	1 $\mu\text{g}/\text{m}^3$	0.053 ppm (100 $\mu\text{g}/\text{m}^3$ )	Same
Sulfur dioxide	Annual average	1 $\mu\text{g}/\text{m}^3$	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	None
	24-hour	5 $\mu\text{g}/\text{m}^3$	365 $\mu\text{g}/\text{m}^3$ (0.14 ppm)	None
	3-hour	25 $\mu\text{g}/\text{m}^3$	None	1,300 $\mu\text{g}/\text{m}^3$ (0.5 ppm)
PM <sub>10</sub>	Annual	1 $\mu\text{g}/\text{m}^3$	50 $\mu\text{g}/\text{m}^3$	50 $\mu\text{g}/\text{m}^3$
	24-hour	5 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$
Lead	Quarterly	None	1.5 $\mu\text{g}/\text{m}^3$	Same

$\mu\text{g}/\text{m}^3$  = Micrograms per cubic meter.

$\text{mg}/\text{m}^3$  = Milligrams per cubic meter.

<sup>1</sup> Standards, other than ozone and those based on annual averages or annual arithmetic means, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.

<sup>2</sup> Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to parts per million by volume, or micromoles of pollutant per mole of gas.

<sup>3</sup> National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the Environmental Protection Agency.

<sup>4</sup> National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after implementation plan is approved by the EPA.

Table 3: Summary Of July 1997 Revised Federal Air Quality Standards

Pollutant	Averaging Time	Standards	
		Primary	Secondary
Ozone (O <sub>3</sub> )	8-hour	0.08 ppm (157 $\mu\text{g}/\text{m}^3$ )	----
Particulate Matter Less than 2.5 micrometers in diameter (PM <sub>2.5</sub> )	24-hour	65 $\mu\text{g}/\text{m}^3$	----
	Annual	15 $\mu\text{g}/\text{m}^3$	----



## Dispersion Model Selection and Modeling Methodology

Dispersion modeling was performed using the EPA's Industrial Source Complex Short-Term 3 (ISCST3) model (Version 00101). The ISCST3 model is a steady-state, multiple-source, Gaussian dispersion model, which includes many options to address unique modeling requirements. Some of these options are discussed below, and the options chosen for HGP are identified.

ISCST3 incorporates simple terrain algorithms for estimating impacts at receptors where ground-level elevations are equal to or less than the heights of the emission sources (stacks). To estimate impacts at receptors with ground-level elevations that exceed the final plume height centerline, the ISCST3 model incorporates complex terrain algorithms from the COMPLEX-1 model. In default mode, the ISCST3 model follows EPA's guidance for calculation of impacts in intermediate terrain, that is, where ground-level elevations are located between the release height and the final plume height centerline. For intermediate terrain receptors, the ISCST3 model calculates concentrations using both simple terrain algorithms and complex terrain algorithms. The model then compares the predicted concentrations at each receptor, on an hourly basis, and the highest concentration per receptor is output from the model.

Based on the land use in the region surrounding HGP, rural dispersion coefficients were assigned. The land use surrounding the site (within a 3-kilometer area surrounding the site) is greater than 50 percent rural. Therefore, rural dispersion coefficients are appropriate.

Technical options selected for the ISCST3 modeling are listed below. These are referred to as the regulatory default options in the ISCST3 Users' Guide:

- Final plume rise
- Buoyancy-induced dispersion
- Stack tip downwash
- Calm processing routine
- Default wind profile exponents (rural)
- Default vertical temperature gradients

The ISCST3 model is a steady state model that can simulate the transport of emissions from point sources, area sources, volume sources and open pits. The ISCST3 model requires the input of various source- and site-specific data. The turbine stacks were modeled as separate point sources. To represent the cooling tower structure, cells were modeled as a series of nine point sources. Parameters required for modeling point sources include source location, stack base elevation, stack height, stack inner diameter, stack gas exit velocity, and stack gas exit temperature. Source parameters used in the screening and refined modeling analyses are summarized in the Screening Analysis of Turbine Operations and the Refined Modeling Analysis sections, respectively.

EPA provides specific guidance to determine whether or not a structure (building) potentially affects pollutant dispersion from a nearby emission source. The guidance states that, if a structure is located within a certain distance from the emission source (stack), downwash effects



on the dispersion of stack emissions must be considered. Stack heights that minimize downwash effects are referred to as Good Engineering Practice (GEP) stack heights. A GEP analysis is performed for two reasons. First, improved dispersion credit cannot be taken for a height greater than the GEP stack height. Second, if a stack is shorter than the GEP formula height, building downwash must be considered when modeling emissions from that stack.

The GEP stack height is defined as the greater of the GEP formula height (defined below) or 65m (213 feet). Although credit cannot be taken for stack heights greater than GEP in the modeling analysis, a higher stack could be built. The GEP formula height is defined as:

$$H_s = H_b + 1.5L_b$$

Where:

$H_s$  = GEP formula height

$H_b$  = Building height

$L_b$  = The lesser building dimension of the height, length, or width

For HGP, an analysis of structures within proximity of the turbines and the cooling towers was performed to ascertain which structure or structures could potentially influence each point source of interest, and thus affect the GEP formula height calculation (and subsequently, any necessary determination of direction-specific building parameters for the modeling analysis). This information was based upon preliminary engineering design data for HGP.

A software package developed by the EPA, Building Profile Input Program (BPIP), was used to assist in the detailed downwash analysis. This program calculates the GEP formula heights and direction-specific building dimensions for input into the ISCST3 model.

RPIT requires the input of building/structure corner coordinates, tank coordinates, stack coordinates, and stack and building/structure heights. The Universal Transverse Mercator (UTM) coordinate system was used to identify the locations of sources and buildings/structures. The ISCST3 model uses the BPIP output (direction specific building dimensions) to calculate aerodynamic building downwash.

The EPA CTSCREEN model (version 94111) was used to better evaluate impacts on elevated terrain. This model provides a more refined treatment of plume impacts in areas of elevated terrain by simulating plume behaviors governed by streamline air flows. CTSCREEN simulates the plume behavior based on assumed worst-case meteorological conditions, and provides a conservative estimate of concentration increases.

The results of the ISCST3 modeling were evaluated to determine the domain of the CTSCREEN refined analysis. All receptors with maximum 24-hour  $PM_{10}$  impacts of  $4.7 \mu g/m^3$  (arbitrary value below the significant impact level for 24-hour  $PM_{10}$  of  $5 \mu g/m^3$ ) or above were identified. Terrain and receptors were developed for CTSCREEN within these 'areas of interest' with spacing at 25 meter intervals. CTSCREEN model options were set according to EPA guidelines and the CTSCREEN user's guide. Additional details of the CTSCREEN analysis are provided in the Refined Modeling Analysis section.



The design heights for the turbine stacks (180 feet) and the cooling tower cell heights (47 feet), which were based on engineering decisions and design limitations, are below the formula GEP heights.

Hourly meteorological data is also required by the ISCST3 model. The required data include surface wind speed, surface wind vector, surface ambient temperature, stability class and mixing height data. Five years (1994-1998) of representative meteorological data from the Palo Verde, Arizona, Nuclear Power Station site were used for the air quality modeling analysis.

The Palo Verde data are typical and representative of the meteorology in the HGP site area. The elevation at the monitoring site is 950 feet above mean sea level (MSL), slightly lower than the elevation range at the HGP siting area. The terrain configuration surrounding both the HGP site area and the meteorological monitoring site are also similar, with generally flat terrain within a one kilometer radius of each. Both sites also have elevated terrain directly to the east and south. The HGP site is located east (on the lee side) of the Eagletail Mountains; the monitoring site is located to the east of Saddle Mountain and the Palo Verde Hills. Both locations are approximately 10 kilometers from "High Terrain", or 900 feet or more above stack base (as defined in Maricopa County Rule 240.206); Eagletail Peak is located southwest of the HGP site, and Signal Mountain is located south-southwest of the monitoring station.

The meteorological data were collected at 60-meters above ground level elevation. Data were recorded for the following parameters: wind speed, wind direction, sigma theta, temperature, dewpoint temperature, and precipitation. Stability classifications were determined from sigma theta.

## **Screening Analysis of Turbine Operations**

The SW 501G combustion turbine package was used for the HGP modeling analyses. The turbine was modeled over a range of operating conditions to determine which operating scenarios generated the maximum estimated air quality impact.

Impacts for annual  $\text{NO}_x$ , 1-hour and 8-hour CO, 24-hour and annual  $\text{PM}_{10}$ , and 3-hour, 24-hour, and annual  $\text{SO}_2$  were estimated using the ISCST3 dispersion model. As described in the Dispersion Model Selection and Modeling Methodology section, the ISCST3 model is a Gaussian model designed to calculate impacts from multiple sources in both simple and complex terrain. Turbine start-ups, cooling towers, and auxiliary source operations were not included in this turbine screening analysis, but were included in the refined modeling analysis to assess total HGP impacts. Facility structures were evaluated for downwash effects using BPIP, and five years of Palo Verde meteorological data were used.

The turbine screening results were used to identify the operating conditions for the various averaging periods. The operating conditions with the highest overall offsite impacts were subsequently used in the refined modeling analysis.



***Emission Rates and Stack Parameters***

Maximum impacts were predicted for the turbines at three different turbine load levels and three different ambient temperatures in the turbine screening analysis. The turbine operating load and temperature combinations were chosen to characterize a wide range of potential operating conditions to accommodate operational flexibility. Emission rates for the long- and short-term averaging periods were assumed to be continuous for each of the turbine screening modeling scenarios. Table 4 presents stack locations, heights, and diameters, based on preliminary engineering design data, used in the modeling analysis.

The SW 501G turbine was analyzed for nine different operating conditions for the turbine screening analysis. Ambient temperatures of 121°F, 70°F, and 14°F were modeled assuming turbine loads of 100 percent (base load), 75 percent, and 50 percent load. Evaporative cooling was considered for both the 121°F and 70°F ambient temperature scenarios for turbine loads of 100 percent. Table 4 presents the HRSG stack parameters and emission rates for the SW 501G used in the turbine screening analysis.

**Table 4: Common Stack Parameters Used For Turbine Screening Analysis**

<b>Parameter SW 501G</b>	<b>Unit 1</b>	<b>Unit 2</b>	<b>Unit 3</b>
Stack Easting (m)	303,619	303,688	303,758
Stack Northing (m)	3,705,788	3,705,787	3,705,786
Stack Height (m)	54.9	54.9	54.9
Stack Diameter (m)	5.79	5.79	5.79



**Table 5: SW 501G Turbine Stack Parameters Used For Turbine Screening Analysis**

Scenario	501G_1	501G_2	501G_3	501G_4	501G_5	501G_6	501G_7	501G_8	501G_9
Load	100%	75%	50%	100%	75%	50%	100%	75%	50%
Temperature (°F)	121	121	121	70	70	70	14	14	14
Condition <sup>1</sup>	E.V.			E.V.			--	--	--
NO <sub>2</sub> (lb/hr) <sup>2</sup>	22.0	16.0	12.2	23.0	18.0	13.3	25.0	20.0	15.0
NO <sub>2</sub> (g/s) <sup>2</sup>	2.772	2.016	1.540	2.898	2.268	1.680	3.150	2.520	1.890
CO (lb/hr) <sup>2</sup>	32.0	23.0	23.7	34.0	26.0	32.3	37.0	31.0	36.3
CO (g/s) <sup>2</sup>	4.032	2.898	3.512	4.284	3.276	4.074	4.662	3.906	4.568
PM10 (lb/hr) <sup>2</sup>	20.0	16.0	15.0	22.0	18.0	17.0	24.0	20.0	18.0
PM10 (g/s) <sup>2</sup>	2.520	2.016	1.390	2.772	2.268	2.142	3.024	2.520	2.268
SO <sub>2</sub> (lb/hr) <sup>2</sup>	4.93	3.59	2.75	5.23	4.10	3.11	5.77	4.64	3.48
SO <sub>2</sub> (g/s) <sup>2</sup>	0.621	0.452	0.347	0.659	0.517	0.392	0.727	0.585	0.438
Gas Exit Temp (°F)	181	180	183	178	180	183	182	179	183
Gas Exit Temp (K)	356	355	357	354	355	357	356	355	357
Gas Exit Velocity (ft/sec)	67.56	53.81	51.81	70.69	58.49	55.74	77.08	64.03	59.12
Gas Exit Velocity (m/sec)	20.59	16.40	15.79	21.55	17.83	16.99	23.49	19.52	18.02

<sup>1</sup> Evaporative cooling (E.V.)

<sup>2</sup> Emissions are per turbine.



### *Modeling Receptor Grid*

Receptors are offsite locations, or points, where the model calculates pollutant impacts. Receptors for the screening analysis were placed approximately every 25 meters along the property boundary and at 100-meter increments to a distance of 1 km, 250-meter increments to a distance of 5 km, and 500-meter increments to insignificant impacts. Additional discrete receptors were located at hilltops and along ridgelines in complex terrain near the HGP. UTM coordinates were used to identify receptor locations. Receptor elevations were obtained from United States Geological Survey (USGS) 7.5 minute (1:24,000 scale) digital elevation models. Impacts at Class I and Class II wilderness areas or at the boundary of the Phoenix Metro Ozone Non-Attainment area were not evaluated during the turbine screening modeling analysis.

### **Turbine Screening Modeling Results**

Table 5 presents the results of the turbine screening analysis. These results were used to select the worst-case operating conditions for refined modeling. The worst case is defined as the highest overall ambient air impacts under HGP's different scenarios of operating loads and ambient temperatures.

Maximum annual NO<sub>x</sub> impacts occurred for a turbine load of 100 percent and an ambient temperature of 14°F, under scenario 501G\_7. Refined annual NO<sub>2</sub> modeling was run assuming more realistic conditions of 70°F and 100 percent load (501G\_4).

Scenario 501G\_9, with an operating load of 50 percent and an ambient temperature of 14°F, leads to the peak 1- and 8-hour CO impacts. CO emission rates for this scenario are highest and the stack exit velocity is low. This affects the ability of the plume to disperse, creating higher impacts than other operating scenarios.

As described above, refined annual average modeling conditions assume an ambient temperature of 70°F and 100 percent load, therefore annual PM<sub>10</sub> impacts were evaluated using scenario 501G\_4. Screening results indicate that the highest modeled 24-hour PM<sub>10</sub> impacts are associated with operations at 100 percent load at 14°F. This maximum impact, however, occurred on a day when the average daily temperature was 92°F, so the 14°F scenario parameters were overly conservative. The minimum 24-hour average temperature for the years 1994 through 1998 is 40°F, and the average is 73°F. Therefore, a 24-hour average temperature of 14°F is considered unrealistic and refined modeling was performed for a 24-hour average temperature of 70°F. For an ambient temperature of 70°F, a turbine load of 100% resulted in the highest predicted PM<sub>10</sub> impacts, thus 24-hour PM<sub>10</sub> impacts were modeled using scenario 501G\_4. Peak SO<sub>2</sub> impacts occurred during periods of high turbine load and low ambient temperature, corresponding to maximum fuel use. The highest 3-hour SO<sub>2</sub> concentrations occurred at 14°F (501G\_7), while the highest 24-hour and annual SO<sub>2</sub> concentrations were based on 70°F and 100 percent load as in the 24-hour PM<sub>10</sub> analysis (501G\_4).



Table 6: Turbine Screening Analysis Results

Scenario	Temp. (F)	Load	Condition	NO <sub>x</sub>		CO		PM <sub>10</sub>		SO <sub>2</sub>	
				Annual (□g/m <sup>3</sup> )	1-hour (□g/m <sup>3</sup> )	8-hour (□g/m <sup>3</sup> )	24-hour (□g/m <sup>3</sup> )	Annual (□g/m <sup>3</sup> )	3-hour (□g/m <sup>3</sup> )	24-hour (□g/m <sup>3</sup> )	Annual (□g/m <sup>3</sup> )
501G_1	121	100%	E.V. <sup>†</sup>	0.50	64.39	22.01	5.19	0.45	7.21	1.28	0.11
501G_2	121	75%	--	0.40	50.34	17.24	4.35	0.40	5.50	0.98	0.09
501G_3	121	50%	--	0.32	62.74	21.60	4.08	0.40	4.22	0.75	0.07
501G_4	70	100%	E.V.	0.52	68.33	23.18	5.71	0.50	7.64	1.36	0.12
501G_5	70	75%	--	0.45	54.91	18.90	4.79	0.45	6.15	1.09	0.10
501G_6	70	50%	--	0.34	68.57	23.75	4.54	0.43	4.67	0.83	0.08
501G_7	14	100%	--	0.54	72.03	24.43	6.05	0.51	8.25	1.45	0.12
501G_8	14	75%	--	0.48	63.20	21.83	5.24	0.48	6.89	1.22	0.11
501G_9	14	50%	--	0.36	74.78	26.04	4.74	0.43	5.19	0.92	0.08

<sup>†</sup> Evaporative cooling (E.V.)



## Refined Modeling Analysis

A refined modeling analysis was performed to estimate offsite criteria pollutant ( $\text{NO}_2$ ,  $\text{CO}$ ,  $\text{SO}_2$ , and  $\text{PM}_{10}$ ) impacts from operational emissions for HGP. Refined modeling included turbine start-ups, cooling tower  $\text{PM}_{10}$  emissions, and auxiliary sources. The ISCST3 model was used to consider impacts in simple, intermediate and complex terrain.

Additionally, 24-hour  $\text{PM}_{10}$  impacts were modeled using CTSCREEN for selected elevated terrain areas. Each hill modeled using CTSCREEN was input to the FITCON terrain preprocessor as a series of digitized contours. The contours were developed from 7.5 minute (1:24,000 scale) USGS DEM files. Contours were input at 10 meter vertical intervals. Where necessary, contours were closed using the FITCON preprocessor assuming a 1 degree angular filter. The minimum critical elevation was set at 340 meters for all hills, just below the stack base elevation. A total of 20 critical elevations for each hill, ranging from 340 meters to the hill top, were calculated using the HCRIT terrain processor.

The modified version of CTSCREEN model was run for all stable and unstable conditions. The modification allowed for an increase in the maximum number of receptors to 2,000 per run. No other coding changes were made. To decrease run-times, the emissions from HGP's cooling towers were conservatively co-located at 8 points rather than at each of the 18 individual cooling cells. Modeled stack parameters for all sources and emission rates for the turbines and diesel fired equipment were input the same as for the ISCST3 modeling.

To maintain operational flexibility, HGP may be required to shutdown and subsequently restart one or more of the turbines. Recently, the effects of turbine start-ups has become of interest from an air quality perspective. Pollutant mass emission rates during start-up can exceed normal operational emission rates because control equipment has not yet reached operating temperatures. The refined modeling analysis evaluates the air quality impacts associated with these transient and infrequent events. Shutdown emissions are not included in the analyses because it has been determined that emissions during a shutdown are less than the full operation emissions that are not deducted for idle turbines during periods of shutdown. Thus, the calculation method used for refined modeling emissions is conservative as compared to a more realistic scenario containing shutdowns, down times, and start-ups.

It is estimated that HGP would require 50 start-ups (10 cold and 40 warm/hot) per turbine annually to maintain the flexibility to respond to market and maintenance needs. Start-ups are classified as hot, warm, and cold based on the duration of the preceding shutdown period. The time required to bring the power block to full rated capacity is highly dependent on a complex series of variables and varies substantially with turbine and plant design. Data for modeling turbine starts are limited and reflect this high degree of variability.

To determine the worst-case start-up emissions, the maximum hourly mass emission rate was selected. For the SW 501G turbine, a cold start is expected to have a 3 hour maximum duration and a warm start would have a 2.4 hour maximum duration. To reflect the practice of holding the turbine in a low-load state during start-up, the exhaust flow rate and temperature were modeled assuming the worst-case low-load (50 percent) turbine scenarios. Start-up conditions for annual



NO<sub>x</sub> modeling are based on an annual average temperature of 70°F and 50 percent load while short-term averaging periods assume 121°F and 50 percent load. The worst-case short-term scenarios assume sequential turbine starts concurrent with non-start-up turbines operating at worst-case conditions, as determined by the screening analysis. Because PM<sub>10</sub> and SO<sub>2</sub> emissions are related to fuel consumption and emissions do not increase during start-up conditions, start-ups do not represent the worst-case emission scenario and were not modeled for the PM<sub>10</sub> and SO<sub>2</sub> refined analyses. Table 6 summarizes the turbine start-up emissions data used in the refined modeling analysis. [Note: HGP has recently submitted a Permit Modification request to increase the CO emissions during start-up (February 2003). The time for start-ups has also been modified. The changes are not expected to alter impact results significantly. Using conservative proration methods, maximum impacts will remain below significant impact levels.]

**Table 7: Start-up Emission Rates and Stack Parameters Per Turbine**

Parameter	Annual Average <sup>1</sup>	1-Hour <sup>2,3</sup>	8-Hour <sup>2,4</sup>
Ambient Temp. (°F)	70	121	121
CTG Load	50%	50%	50%
Stack Temp. (K)	357	357	357
Exit Veloc (m/s).	16.99	15.79	15.79
NO <sub>x</sub> Emissions	16,770 lb/yr	--	--
CO Emissions	--	2,000 lb/hr	827 lb/hr

<sup>1</sup> Stack parameters are based on an annual average temperature of 70°F and low-load conditions (501G\_6). Annual emissions are based on 10 cold starts and 40 warm starts.

<sup>2</sup> Stack parameters based on worst-case low-load stack parameters (501G\_3).

<sup>3</sup> Emissions are based on the 1<sup>st</sup> hour of a 3-hour cold-start. [Note: Permit Modification 3 submitted to MCESD February 2003, increases the 1-hour maximum emission rate from 2000 lb/hr to 2300 lb/hr.]

<sup>4</sup> 8-hour emissions are for a 3-hour cold-start (827 lb/hr= 2,480 lb CO per start / 3 hours). [Note: Permit Modification 3 submitted to MCESD February 2003, corrects the 8-hour emission rate (including the increase for start-up) from 827 lb/hr to ((3000 lb/(1.46 hrs start-up)+37 lb/(6.54 hrs operation))/8 hrs)=375 lb/hr.]

The refined modeling also included emissions from HGP's auxiliary sources. The HGP design includes one diesel-fired firewater pump and one diesel-fired emergency generator. Each engine would be tested for up to one hour weekly resulting in 52 hours per year of non-emergency use. Criteria pollutant emission estimates for the emergency generator and firewater pump are described in the HGP PSD and Title V Permit Application materials. Cooling tower drift would contribute to HGP PM<sub>10</sub> emissions. The two cooling towers each consist of nine cells that were modeled as individual point sources.

The following worst-case operating scenarios were used in refined modeling to evaluate compliance with ambient air quality standards:

Annual NO<sub>x</sub>:

- 3 turbines operating for 8,634 hours per year at 100 percent load and 70°F ambient temperature.



- 10 cold-starts and 40 warm/hot starts per turbine (accounts for 126 hours operation per year)
- Firewater pump and generator testing, each 52 hours per year.

1-Hour CO:

- 1 turbine cold starting.
- 2 turbines operating at 50 percent load and 14°F ambient temperature.
- Generator testing for 1 hour.

8-Hour CO:

- 3 turbines cold starting.
- 3 turbines operating at 50 percent load and 14°F ambient temperature.
- Firewater pump and generator tests for 1 hour each.

24-Hour PM<sub>10</sub>:

- 3 turbines operating at 100 percent load and 70°F ambient temperature.
- 18 cooling tower cells.
- Firewater pump and generator tests for 1 hour each.

Annual PM<sub>10</sub>:

- 3 turbines operating for 8,760 hours per year at 100 percent load and 70°F ambient temperature.
- 18 cooling tower cells.
- Firewater pump and generator testing, each 52 hours per year.

3-Hour SO<sub>2</sub>:

- 3 turbines operating at 100 percent load and 14°F ambient temperature.
- Firewater pump and generator tests for 1 hour each.

24-Hour SO<sub>2</sub>:

- 3 turbines operating at 100 percent load and 70°F ambient temperature.
- Firewater pump and generator tests for 1 hour each.

Annual SO<sub>2</sub>:

- 3 turbines operating for 8,760 hours at 100 percent load and 70°F ambient temperature.
- Firewater pump and generator testing, each 52 hours per year.

The MCESD requested an analysis be performed to demonstrate that HGP would not add to the ozone concentrations in the non-attainment area of Phoenix. Modeling with ISCST3 was performed to predict NO<sub>2</sub> (an ozone precursor) impacts along the Maricopa County Phoenix Metro Ozone Non-Attainment area. This modeling analysis was performed for the worst case annual NO<sub>x</sub> emissions scenario.

### ***Emission Rates and Stack Parameters***

Table 8 summarizes the turbine and auxiliary source stack parameters used in the refined modeling analysis. Modeled pollutant emissions rates are presented in detail in PSD and Title V Permit Application materials submitted by HGP. [Note: During the recent Permit Modification



request to increase the CO emissions during start-up, slight changes in stack parameters during start-up were also addressed. These changes are not expected to alter impact results significantly, and actually are likely to create improved dispersion.]

**Table 8: Refined Modeling Source Parameters**

<b>Source Description</b>	<b>Base Elevation (meters)</b>	<b>Release Height (meters)</b>	<b>Stack Exit Temperature (K)</b>	<b>Stack Exit Velocity (meters/second)</b>	<b>Stack Inner Diameter (meters)</b>
<b>Annual NO<sub>x</sub></b>					
Turbine	342.9	54.86	354	21.55	5.79
Start-up Turbine	342.9	54.86	357	16.99	5.79
<b>1-Hour CO</b>					
Turbine	342.9	54.86	357	18.02	5.79
Start-up Turbine	342.9	54.86	357	15.79	5.79
<b>8-Hour CO</b>					
Turbine	342.9	54.86	357	18.02	5.79
Start-up Turbine	342.9	54.86	357	15.79	5.79
<b>24-Hour &amp; Annual PM<sub>10</sub></b>					
Turbine	342.9	54.86	354	21.55	5.79
<b>3-Hour SO<sub>2</sub></b>					
Turbine	342.9	54.86	356	23.49	5.79
<b>24-Hour &amp; Annual SO<sub>2</sub></b>					
Turbine	342.9	54.86	354	21.55	5.79
<b>Auxiliary Sources</b>					
Firewater pump	342.9	6.05	649	55.78	0.152
Emergency generator	342.9	6.05	746	180.4	0.203
Cooling tower cell	342.9	14.33	309	5.82	10.14

### ***Modeling Receptor Grids***

A Cartesian coordinate receptor grid was developed around HGP and surrounding area to assess ground-level ambient air quality impacts and to identify the extent of significant impacts. Receptors were placed along the HGP fenceline at approximately 25-meter increments. A grid with 100-meter spacing was placed surrounding the facility to a distance of 1 km, receptors at 250-meter spacing to a distance of 5 km, and 500-meter spacing to a distance of 10 km. Additional discrete receptors were located at hilltops and along ridgelines in complex terrain to a distance of 10 km from HGP. UTM Coordinates were used to identify the receptor locations. Elevations at receptor locations were obtained from USGS 7.5-minute (1:24,000 scale) digital elevation models (DEMs).



Fine receptor grids with 25-meter resolution were then placed surrounding the location of the maximum concentration for each pollutant and averaging period, as predicted using the coarse grid model runs. These fine grid receptors extended a minimum of 0.5 km from the coarse grid maximums and the model was re-run to capture the more exact locations of maximum concentration. Where maximum concentrations occurred at the edge of a fine grid, additional receptors were added until the point of maximum impact was identified within a fine grid. For the refined CTSCREEN modeling in elevated terrain, receptors were input at 25 meters on center and their elevations were obtained from 7.5 minute DEM data. Receptors were located to cover the entire hill area as defined by the lowest elevation contour available for that hill. All receptors were placed within complex terrain. Concentrations within the site boundary were not calculated. To analyze HGP's potential contribution to ozone concentrations in Phoenix,  $\text{NO}_2$  (a precursor to ozone) concentrations were estimated at the Phoenix Metro Ozone Non-Attainment area east of HGP. UTM coordinates were used to identify the receptor locations. Elevations at receptor locations were obtained from USGS 7.5-minute DEMs.

At the request of the Federal Land Manager (FLM), representing both the Bureau of Land Management (BLM) and the USFS, air quality impacts were estimated at the nearest Class I Area. The Mazatzal Wilderness Area is the closest to HGP, at 144 km. Superstition Wilderness Area is the next closest, at 160 km. For long-range transport estimates, Gaussian-based dispersion models are commonly used for distances up to 100 km (EPA, 1995b). Impacts were modeled with ISCST3 to provide an idea of the potential impact at Mazatzal. Receptors were placed at both 100 km northeast of HGP in the direction of the Mazatzal Wilderness Area, and at the actual Mazatzal boundary at 144 km. The modeled receptor elevation was set equal to the elevation of the closest point along the wilderness area boundary (762 m). The UTM Coordinates were used to identify the receptor locations. Elevations at receptor locations were obtained from USGS 7.5-minute DEMs. Modeled impacts at 100 km provide a very conservative estimate for the Mazatzal Wilderness Area. Modeled impacts at 144 km are provided to indicate the extent to which impacts will decrease with increasing distance.

### ***Refined Modeling Results***

The maximum modeled highest 1<sup>st</sup> high impacts resulting from HGP's emissions of  $\text{NO}_x$ , CO,  $\text{SO}_2$ , and  $\text{PM}_{10}$  are below significance criteria for all pollutant averaging periods. Table 8 presents a comparison of the modeled results with PSD significant impact levels (SILs) and Class II PSD increment levels. A discussion of maximum concentration by pollutant is presented below:

**$\text{NO}_2$  Impacts.** The maximum modeled annual  $\text{NO}_x$  impact is  $0.56 \mu\text{g}/\text{m}^3$ , below the PSD SIL of 1.0. Using the EPA default Applied Ratio Method (ARM) value of 0.75 for considering  $\text{NO}_x$  emission interaction with ambient ozone, the annual  $\text{NO}_2$  impact is reduced to  $0.42 \mu\text{g}/\text{m}^3$ . The peak impact is located approximately 7.5 km northeast of HGP.

**CO Impacts.** The modeled 1-hour and 8-hour impacts are  $1,501 \mu\text{g}/\text{m}^3$  and  $234 \mu\text{g}/\text{m}^3$ , respectively, and both are below PSD SIL's. The peak 1- and 8-hour CO impacts are located approximately 6 km and 6.5 km southeast of HGP respectively. CO impacts are largely influenced by turbine start-ups, which are a temporary condition and are not representative of



normal facility operations. [Note: HGP's recent Permit Modification request to increase the CO emissions during start-up gives the conservative, prorated, 1- and 8-hour impacts as 1,726  $\mu\text{g}/\text{m}^3$  and 269  $\mu\text{g}/\text{m}^3$ , respectively. These maximum impacts are still below significant impact levels.]

**PM<sub>10</sub> Impacts.** Particulate emission (PM<sub>10</sub>) impacts from the turbines, cooling towers and auxiliary sources were assessed for both annual and 24-hour averaging periods using the ISCST3 model. The maximum annual PM<sub>10</sub> impact is 0.61  $\mu\text{g}/\text{m}^3$ , and occurs on the eastern edge of the HGP fenceline. Impacts for 24-hour PM<sub>10</sub>, as modeled using ISCST3, exceeded 4.7  $\mu\text{g}/\text{m}^3$  in elevated terrain approximately 4 to 7.5 km southeast of HGP. These impacts occurred on eight separate hills. For all hills modeled using CTSCREEN, the maximum modeled impact is 4.1  $\mu\text{g}/\text{m}^3$ . The maximum modeled 24-hour impact, considering the ISCST3 analysis and the CTSCREEN analysis at the eight hill sites, is 4.7  $\mu\text{g}/\text{m}^3$ . This maximum occurs in the ISCST3 modeling domain and is located in elevated terrain approximately 7.5 km southeast of HGP. Based on the CTSCREEN analyses, this impact would likely be lower using CTSCREEN. Neither the annual or 24-hour impact exceeds the PSD SIL's.

**SO<sub>2</sub> Impacts.** SO<sub>2</sub> impacts from the turbines and auxiliary sources were assessed for 3-hour, 24-hour, and annual averaging periods. The maximum modeled SO<sub>2</sub> impacts are 15.7  $\mu\text{g}/\text{m}^3$  and 1.4  $\mu\text{g}/\text{m}^3$  for 3-hour and 24-hour, respectively. The maximum annual SO<sub>2</sub> impact is 0.12  $\mu\text{g}/\text{m}^3$ . All predicted impacts are below PSD SIL's. Peak 3-hour impacts are located along the southern fenceline while 24-hour impacts occur approximately 7.5 km southeast from HGP. Maximum annual impacts are located 7.5 km to the northeast.



Table 8. Harquahala Operating Impacts Modeling Results Compared With PSD Impact Levels And Class II PSD Increments

Pollutant	Averaging Period	Modeled Impact <sup>1</sup> ( $\mu\text{g}/\text{m}^3$ )	Location UTM Coordinates (East, North) (meters)	PSD Significant Impact Level ( $\mu\text{g}/\text{m}^3$ )	Class II PSD Increment ( $\mu\text{g}/\text{m}^3$ )
NO <sub>2</sub>	Annual <sup>2</sup>	0.42	308470, 3711508	1	25
	Maximum 1-hour <sup>3</sup>	1,501	308487, 3701950	2,000	--
	Maximum 8-hour <sup>3</sup>	234	308756, 3701731	500	--
PM <sub>10</sub>	Maximum 24-hour	4.7	4	5	30
	Annual	0.61	303997, 3706055	1	17
SO <sub>2</sub>	Maximum 3-hour	15.7	303797, 3705597	25	512
	Maximum 24-hour	1.4	308200, 3699875	5	91
	Annual	0.12	308470, 3711508	1	20

<sup>1</sup> Maximum modeled highest 1<sup>st</sup>-high impact.

<sup>2</sup> Based on Applied Ratio Method (ARM) using a 0.75 ratio factor applied to maximum annual NO<sub>x</sub>.

<sup>3</sup> HGP's recent Permit Modification request (February, 2003) gives the conservative, prorated, impacts as 1,726  $\mu\text{g}/\text{m}^3$  (1-hr) and 269  $\mu\text{g}/\text{m}^3$  (8-hr).

<sup>4</sup> Modeled impacts exceeding 4.7  $\mu\text{g}/\text{m}^3$ , as predicted using the ISCST3 model, were modeled using CTSCREEN. The maximum modeled impact is 4.69 and occurs in multiple locations within the ISCST3 modeling domain.



**Ozone Contribution.** The MCSESD requested that an analysis be performed demonstrating that HGP would not add to the ozone concentrations in the non-attainment area of Phoenix. Modeling with ISCST3 was performed to estimate NO<sub>2</sub> (an ozone precursor) concentrations along the Maricopa County Phoenix Metro Area Ozone Non-Attainment area. The maximum annual NO<sub>x</sub> concentration from HGP was estimated to be 0.03 µg/m<sup>3</sup>.

Based on these low NO<sub>x</sub> concentrations predicted at the Phoenix Metro Ozone Non-Attainment area, HGP is not anticipated to impact the attainment status of the Phoenix area. At the time of this analysis (2000), Phoenix baseline annual NO<sub>2</sub> concentrations were 62 µg/m<sup>3</sup>. The potential contribution from HGP is significantly less than baseline conditions and is also well below the EPA's SIL which is interpreted to mean that the project will not "cause or contribute" to a violation of the NAAQS.

**Class I Wilderness Area Impacts.** The FLM requested that an analysis be performed demonstrating that HGP would not lead to significant impacts at the Mazatzal Wilderness Area. Modeled impacts for NO<sub>x</sub>, PM<sub>10</sub>, and SO<sub>2</sub> at the conservative 100 km receptor are presented in Table 9 and fall well below PSD SIL's. HGP is not expected to result in adverse impacts at the nearest Class I area.

**Table 9: Harquahala Operating Impacts Modeling Results For MAZATZAL Wilderness Area Compared With PSD SIGNIFICANT Impact Levels And Class I PSD Increments**

Pollutant	Averaging Period	Modeled Impact <sup>1</sup> (µg/m <sup>3</sup> )	PSD Significant Impact Level (µg/m <sup>3</sup> )	Class I Increment (µg/m <sup>3</sup> )
NO <sub>2</sub>	Annual <sup>2</sup>	0.01	1	2.5
CO	Maximum 1-hour	25	500	--
	Maximum 8-hour	2.6	2000	--
PM <sub>10</sub>	Maximum 24-hour	0.1	5	8
	Annual	0.01	1	4
SO <sub>2</sub>	Maximum 3-hour	0.14	25	25
	Maximum 24-hour	0.02	5	5
	Annual	< 0.01	1	2

<sup>1</sup> Maximum modeled impact. [Note: CO impacts were not prorated for proposed revision to start-up emissions (HGP's Permit Modification request, February, 2003).]

<sup>2</sup> Based on Applied Ratio Method (ARM) using a 0.75 ratio factor applied to maximum annual NO<sub>x</sub>.

[Note: A CD-ROM containing model input and output files has been provided to the MCESD as part of HGP's PSD and Title V Application materials.]



## Summary of Results

Air quality impact modeling for HGP demonstrates that impacts for  $\text{NO}_x$ , CO,  $\text{PM}_{10}$ , and  $\text{SO}_2$  are all below applicable SILs. Because the impacts would be insignificant, increment consumption would be insignificant and no additional analyses are required.

### AQRV IMPACTS

The EPA PSD regulations categorize attainment areas by the degree of air quality degradation allowed. Specific national parks and wilderness areas are classified as Class I areas. PSD regulations are designed to maintain the pristine conditions of these Class I areas by protecting AQRVs, which include visibility, terrestrial, aquatic, and biological resources. The EPA PSD regulations require an AQRV analysis for proposed major sources that "...may affect a Class I area" [40 CFR 52.21(p)(1)]. The meaning of the term "may affect" is interpreted by EPA policy to include major sources and modifications proposing to locate within 100 kilometers (km) of a Class I area. The potential for Class I impacts associated with HGP is discussed in the AQRVs in Class I Areas section.

The EPA PSD regulations do not require an AQRV analysis for Class II Wilderness Areas. However at the request of the FLM, an analysis for Class II areas within 50 kilometers of the HGP site was made. The AQRVs in Class II Areas section describes the analyses performed for potential visibility impacts at the specified Class II areas, as well as for other AQRVs estimated from the HGP's  $\text{NO}_x$  and  $\text{SO}_2$  emissions due to deposition of nitrates (expressed as  $\text{HNO}_3$ ) and sulfates (expressed as  $\text{HSO}_3$ ).

### AQRVs in Class I Areas

This section addresses potential impacts on AQRVs at the nearest Class I areas to HGP, which are the Mazatzal and Superstition Wilderness Areas, located approximately 144 km northeast and 160 km east of the site, respectively. These Class I areas are administered by the USFS. Because each area is located over 100 km from HGP, EPA policy would consider them not to be significantly impacted by HGP. The clean-burning nature of natural gas combustion coupled with low sulfur dioxide emissions and heavily-controlled nitrogen oxide emissions would support the conclusion that potential visibility and nitrate/sulfate deposition impacts would be insignificant. Under the EPA PSD regulations, however, the applicable FLM, which in this case is the USFS, has the final authority in determining whether a proposed major project would have a potential significant impact on AQRVs in Class I areas. Although outside the 100 km Class I significant impact area defined by EPA policy, a supplemental AQRV analysis was performed for the Mazatzal Wilderness Area to provide additional information in this permit application for the FLM. The Mazatzal Wilderness Area is slightly closer to HGP than the Superstition Wilderness Area, and with respect to the Palo Verde meteorological data used in the analysis, is in the predominate downwind direction. Therefore, any impacts calculated for the Superstition Wilderness Area would be lower.



### Visibility in Class I Areas

To assess visibility beyond 50 km from a proposed project, the USFS requires that the analysis be based on an assessment of the impact on "regional haze" at the closest boundary of the Class I area. The EPA program VISCREEN (Version 1.01) is used for distances within 50 km of the proposed source. The NPS has similar requirements for visibility impact screening for areas under its jurisdiction. The Class I areas addressed here are beyond 50 km from HGP, thus the "regional haze" assessment described below was performed with Level I screening methods outlined in the Interagency Workgroup on Air Quality Modeling (IWAQM), as amended by supplemental procedures received from the NPS at the time of this analysis.

Visibility is usually characterized by either visual range (VR) (the greatest distance that a large dark object can be seen) or by the light-extinction coefficient ( $b$ ) (the attenuation of light per unit distance due to scattering and absorption by gases and particles in the atmosphere). These parameters are related as follows:

$$VR = \frac{3,912}{b} \quad (1)$$

where VR is expressed in kilometers and extinction coefficient ( $b$ ) in inverse megameters ( $\text{Mm}^{-1}$ ). The basis of the regional haze assessment is a calculation of the change in the light extinction coefficient. A percent change of less than 5% is considered insignificant.

Particle scattering can be broken down by the contributions of different particulate species. These are generally broken down into two size fractions, fine particles ( $\text{PM}_{2.5}$ ) (particles with mass mean diameters less than or equal to  $2.5 \mu\text{m}$ ) and coarse particles (mass mean diameters greater than  $2.5 \mu\text{m}$  but less than or equal to  $10 \mu\text{m}$ ). The emissions of concern from HGP ( $\text{NO}_x$ ,  $\text{SO}_x$ , and  $\text{PM}_{10}$ ) would result in atmospheric aerosols in the fine particulate fraction but not the coarse fraction; that is, nitrates, sulfates, and organic aerosols. The particulate organic aerosols in natural gas combustion would be predominately less than  $1 \mu\text{m}$  in diameter. Therefore, the extinction coefficient from the proposed source ( $b_{\text{source}}$ ) would be the sum of the scattering coefficient due to nitrates ( $b_{\text{NO}_3}$ ), sulfates ( $b_{\text{SO}_4}$ ) and organic aerosols ( $b_{\text{OC}}$ ):

$$\begin{aligned} b_{\text{source}} &= b_{\text{NO}_3} + b_{\text{SO}_4} + b_{\text{OC}} \\ \text{where: } b_{\text{NO}_3} &= 3 [\text{NH}_4\text{NO}_3]f(\text{RH}) \\ b_{\text{SO}_3} &= 3 [(\text{NH}_4)_2\text{SO}_4]f(\text{RH}) \\ b_{\text{OC}} &= 4 [\text{OC}] \end{aligned} \quad (2)$$

To calculate these coefficients, the estimated airborne concentrations of ammonium nitrate ( $\text{NH}_4\text{NO}_3$ ), ammonium sulfate ( $(\text{NH}_4)_2\text{SO}_4$ ), and organic aerosols (i.e.,  $\text{PM}_{10}$ , assumed to be all less than  $\text{PM}_{2.5}$ ) attributable to the source are needed at the closest Class I boundaries. Because nitrate and sulfate aerosols are hygroscopic, there is an additional factor based on relative humidity [ $f(\text{RH})$ ] since the addition of water enhances light scattering. Concentrations of  $\text{NH}_4\text{NO}_3$  and  $(\text{NH}_4)_2\text{SO}_4$  were estimated from modeled  $\text{NO}_x$  and  $\text{SO}_2$  impacts. The ISCST3 model was used with the same emission and source configurations described in the Refined Modeling Analysis section to calculate  $\text{NO}_x$ ,  $\text{SO}_2$ , and  $\text{PM}_{10}$  impacts at 100 km from HGP along



a straight-line direction from the site to the Mazatzal Wilderness Area and at the 144 km nearest boundary location. Maximum 24-hour-average concentrations were calculated pursuant to guidance received from the NPS. The predicted  $\text{NO}_x$  impacts were converted to potential nitrate ions ( $\text{NO}_3$ ) by multiplying by a worst-case (winter) nitrate conversion factor of 0.4, and then by the molecular weight ratio of  $\text{NO}_3$  to  $\text{NO}_2$  (1.348). Concentrations of  $\text{NH}_4\text{NO}_3$  were then obtained by multiplying by the molecular weight ratio of  $\text{NH}_4\text{NO}_3$  to  $\text{NO}_3$  (1.290). The predicted  $\text{SO}_2$  impacts were converted to potential sulfate ions ( $\text{SO}_4$ ) by the molecular weight ratio of  $\text{SO}_4$  to  $\text{SO}_2$  (1.500). A worst-case sulfate conversion factor of 1.0 was used since no other guidance was available. This represents a conservative assumption because, in actuality, 100% of the  $\text{SO}_2$  would not convert to sulfate.  $(\text{NH}_4)_2\text{SO}_4$  concentrations were then obtained by multiplying by the molecular weight ratio of  $(\text{NH}_4)_2\text{SO}_4$  to  $\text{SO}_4$  (1.375).

The maximum 24-hour  $\text{NO}_x$  impacts at the 100 km and 144 km receptors are 0.0102 and 0.0646  $\mu\text{g}/\text{m}^3$ , respectively. This yields estimated  $\text{NH}_4\text{NO}_3$  concentrations of 0.071 and 0.045  $\mu\text{g}/\text{m}^3$ . The maximum 24-hour  $\text{SO}_2$  impacts at 100 km and 144 km are 0.0229 and 0.0146  $\mu\text{g}/\text{m}^3$ , respectively, resulting in estimated  $(\text{NH}_4)_2\text{SO}_4$  concentrations of 0.047 and 0.030  $\mu\text{g}/\text{m}^3$ . The maximum 24-hour  $\text{PM}_{10}$  impacts at 100 km and 144 km are 0.0980 and 0.0624  $\mu\text{g}/\text{m}^3$ , respectively. Applying a representative wintertime relative humidity for the region of 57% results in a relative humidity factor of 1.345 using the NPS method for the Equation (2) calculation. Using Equation (2) yields source extinction coefficients,  $b_{\text{source}}$ , of 0.8676 and 0.5520  $\text{Mm}^{-1}$  for the 100 km and 144 km receptors, respectively. This is compared with the background extinction coefficient,  $b_{\text{back}}$ , calculated from Equation (1) assuming a conservative background standard visual range (SVR) for the HGP area of 225 km. This SVR yields a calculated  $b_{\text{back}}$  of 17.387  $\text{Mm}^{-1}$  using Equation (1). The calculated percent change in the extinction coefficient ( $b_{\text{source}}/b_{\text{back}}$ ) at 100 km from HGP is therefore (0.8676/17.387), or 5.0 percent. The calculated percent change in the extinction coefficient at 144 km is 3.2 percent. Thus, the anticipated worst-case change in visibility is less than the 5.0 percent level, for which no further analysis is necessary to demonstrate no significant degradation to visibility at Class I areas.

The worst-case 5.0 percent change at 100 km distance only occurs on one day; the second high impacts (second worst-case day) result in a percent change in the extinction coefficient of 4.2 percent. These analyses suggest that the HGP's actual visibility impacts at either the Mazatzal or Superstition Wilderness Areas would be less than significant.

### ***Nitrate and Sulfate Deposition in Class I Areas***

A major pathway by which air pollutants interact with ecosystems is through the soil. In most terrestrial ecosystems, soil is the principal repository for air contaminants of an anthropogenic origin. This can have an effect on vegetation, aquatic, and biological resources. Air pollutants may be transferred from the atmosphere to the ecosystem by a variety of mechanisms, including precipitation scavenging (wet deposition), dry deposition (including sedimentation and impaction), chemical reaction, and absorption (including plant uptake and assimilation). For HGP, the pollutant of concern is  $\text{NO}_x$ .  $\text{NO}_x$  reacts readily with soils and is usually converted to nitrate. A change in soil nitrate levels can cause numerous biochemical and physiological effects in plants, including inhibition of amino acid and protein formation, fatty acid and lipid



production, carbon fixation (photosynthesis), and respiration. The possible adverse result is suppressed growth, and in extreme cases, vegetation may die.

NO<sub>x</sub> emissions can also affect aquatic resources through nitrogen deposition. Acid neutralizing capacity (ANC), or alkalinity levels, can be used to measure a water body's ability to absorb nitrogen and withstand acidification. Several factors influence ANC, such as bedrock geology, the degree of soil weathering, watershed size and hydraulic detention. The higher the ANC, the more resistant the water is to acidification. If nitrogen deposition exceeds the ANC, or the buffering capacity, then the ANC is diminished, pH drops, and acidification may occur. Another potential impact associated with nitrogen deposition is increased algae and plant growth due to the added nitrogen. After dense algal mats cover the water surface, subsurface algae dies and leads to oxygen deprivation during decay. The results are stressed aquatic resources and potential fish kills.

As discussed above, the Mazatzal and Superstition Wilderness Areas are more than 100 km from HGP and would therefore not be considered under EPA policy to be significantly impacted. However, to provide additional information to the USFS, estimates of nitrate and sulfate deposition were performed at 100 km from HGP along a straight line to the Mazatzal Wilderness Area. Per IWAQM guidance, the maximum annual NO<sub>x</sub> impact modeled at this location was assumed to deposit as nitrate, expressed as HNO<sub>3</sub>. HNO<sub>3</sub> was calculated by multiplying the modeled NO<sub>x</sub> by the HNO<sub>3</sub>-to-NO<sub>2</sub> molecular weight ratio (1.37). The maximum annual SO<sub>2</sub> impact modeled at this location was assumed to deposit as SO<sub>2</sub> (also per IWAQM guidance), so no further conversions were necessary. Per guidance received from the NPS, these calculated HNO<sub>3</sub> and SO<sub>2</sub> concentrations were then converted to potential annual deposition by multiplying by an assumed deposition velocity of 0.05 m/s, the number of seconds in a year ( $3.1536 \times 10^7$  seconds), and a factor of 2 to account for both wet and dry deposition. This gives deposition in units of µg/m<sup>2</sup>, which is converted to kg/hectare (kg/ha) by multiplication by 10<sup>-5</sup>. These calculations result in an estimated annual nitrate impact of 0.50 kg/ha-yr and an annual sulfate deposition of 0.08 kg/ha-yr:

Nitrate:

$$0.0114 \mu\text{g}/\text{m}^3 \times 1.37 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 0.49 \text{ kg/ha-yr}$$

Sulfate:

$$0.0024 \mu\text{g}/\text{m}^3 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 0.08 \text{ kg/ha-yr}$$

At the time of this analysis, the USFS did not have a specific significance level for annual nitrate and sulfate deposition for either the Mazatzal or Superstition Wilderness Areas. However, for Class I areas in California, the USFS has published annual nitrogen and sulfur depositions of less than 3 kg/ha-yr and 5 kg/ha-yr, respectively, for most terrestrial ecosystem as the "no injury levels". General soil conditions in California are different than in Arizona, however, use of California "no injury levels" coupled with the NPS finding that 0.26 kg/ha-yr nitrate poses no significant impact in Saguaro National Park for the Desert Basin Generating Project, an area with ecosystems similar to the Mazatzal and Superstition Wilderness Areas, suggests that the above maximum deposition values should not present significant ecosystem impacts. Furthermore, the actual impacts at these Class I areas should be less than the above prediction at 100 km from HGP.



## AQRVs in Class II Areas

At the request of the FLM, potential AQRV impacts at Class II wilderness areas were addressed. These areas include: Bighorn and Hummingbird Springs to the north, Eagletail to the west, and Signal Mountain to the south. They are located approximately 10 kilometers to 32 kilometers from HGP. This analysis is not a PSD requirement, and there are no established criteria for assessing potential AQRV impacts in Class II areas. The results of this section are presented for informational purposes only.

### *Visibility in Class II Areas*

A visibility screening analysis was conducted to assess the impact of HGP's emissions on visibility at the four Class II Wilderness Areas listed above. The EPA program VISCREEN (Version 1.01) was used, which is more appropriate for visibility screening than a regional haze analysis for areas within 50 km of a proposed source. This section describes the modeling methodology, input parameters, and model predictions.

Visual plume impacts were assessed with VISCREEN as recommended by the EPA *Workbook for Plume Visual Impact Screening and Analysis*. This analysis estimates the presence of a visible plume to a hypothetical observer who is located at the closest boundary of wilderness areas.

VISCREEN uses two scattering angles to calculate potential plume visual impacts for cases where the plume is likely to be brightest (10 degrees azimuth for the forward scatter case) and darkest (140 degrees azimuth for the backward scatter case). The forward scatter case yields very bright plumes because the sun is placed nearly directly in front of the observer, which would tend to maximize the light scattered by the plume. The backward scatter case yields the darkest possible plumes as the sun is placed directly behind the observer. For terrain viewing backgrounds, the terrain is assumed to be dark and located as close to the observer and the plume as possible. Scattering of green light is assumed (wavelength = 0.55  $\mu\text{m}$ ) since the eye is most sensitive to intensity changes in green. The observer is a hypothetical person at the boundary of each wilderness area located closest to HGP.

The VISCREEN analysis provides two measures of potential plume impacts. The first measure is plume contrast, which is the relative difference in light intensity between light scattered from the plume and light scattered from the background. This is caused by the same phenomena as discussed in the regional haze analyses described above; that is, the relative difference in the light extinction coefficient between viewing light against background and against the plume.

VISCREEN also provides a second measure of plume perceptibility, the total color contrast,  $\Delta E$ , since plume perceptibility is a function of both brightness and color. This supplements the first contrast measure with contrast calculated from an integrated function of light wavelengths for the three primary colors in the visible light spectrum: red, green, and blue. Green is used in the brightness component of the calculation; a ratio of red to green light is used for the color or "hue" that is reflected; and a ratio of green to blue light is used as the measure of the strength or density of the color (often called the "saturation").



The visibility analysis assumes all three turbines are operating at 100 percent load under Scenario 501G\_7 operating conditions. Under this operating condition, the combined turbine PM<sub>10</sub> and NO<sub>x</sub> emission rates are 9.07 g/s and 9.45 g/s, respectively. No specific stack parameters are required for model input.

A Level 2 visibility analysis was performed following methodologies outlined in the EPA *Workbook for Plume Visual Impact Screening and Analysis*. A Level 2 visibility analysis considers more realistic inputs representing the source and the specific wilderness area. These inputs could include representative particle size distribution for the plume and background which differ from those used as screening defaults in a Level 1 analysis. Additional refinements consider local topography and actual meteorological conditions either at the source or at the wilderness area. For the purposes of this analysis, five years of representative meteorological data collected at the Palo Verde Nuclear Generating Station were analyzed. The most representative worst case meteorological condition was used as input to the VISCREEN model. The worst case meteorological condition is defined as "the sum of all frequencies of occurrence of conditions worse than this condition totals one percent (i.e., about four days per year)". However, these conditions do not include wind speeds resulting in a travel time from the source to the Class II area of greater than 12 hours. Table 10 summarizes inputs used in the VISCREEN model.

The VISCREEN Level 2 analysis resulted in the highest plume contrasts in the Bighorn and Hummingbird Wilderness areas. A maximum plume contrast of 0.052 occurred from HGP when the observer looks in a direction against the sky and toward the sun. A maximum plume contrast of 0.059 occurred from HGP when the observer looks in the direction of the terrain and the sun. For other Class II wilderness areas, and for views against the sky and terrain with the sun behind the observer, the calculated contrasts were less. Visibility results for all Class II Wilderness Areas included in this analysis are summarized in Table 10.

**Table 10: Level II Visibility Analysis – Viscreen Model Inputs**

<b>Inputs</b>	<b>Bighorn Mountains</b>	<b>Hummingbird Springs</b>	<b>Eagletail Mountains</b>	<b>Signal Mountain</b>
PM <sub>10</sub> Emissions (g/s):	9.07	9.07	9.07	9.07
NO <sub>x</sub> Emissions (g/s):	9.45	9.45	9.45	9.45
Background Visual Range (km):	225	225	225	225
Source-Observer Distance (km):	9.97	12.58	13.63	31.46
Minimum Source-Wilderness Distance (km):	9.97	12.58	13.63	31.46
Maximum Source-Wilderness Distance (km):	17.83	27.27	34.08	35.65
Plume-Source-Observer Angle (degrees):	11.25	11.25	11.25	11.25
Stability:	D (4)	D (4)	D (4)	D (4)
Wind Speed:	4	4	7	2



Table 11: Level II Visibility Analysis Results

<b>Bighorn Mountains Wilderness Area</b>			
<b>Sky</b>		<b>Terrain</b>	
Delta E (theta = 10) <sup>1</sup>	2.437	Delta E (theta = 10)	6.930
Delta E (theta = 140) <sup>2</sup>	0.645	Delta E (theta = 140)	0.259
Contrast (theta = 10)	0.051	Contrast (theta = 10)	0.024
Contrast (theta = 140)	-0.018	Contrast (theta = 140)	0.001
<b>Hummingbird Springs Wilderness Area</b>			
Delta E (theta = 10)	2.531	Delta E (theta = 10)	8.266
Delta E (theta = 140)	0.590	Delta E (theta = 140)	0.597
Contrast (theta = 10)	0.052	Contrast (theta = 10)	0.059
Contrast (theta = 140)	-0.018	Contrast (theta = 140)	0.008
<b>Eagletail Mountains Wilderness Area</b>			
Delta E (theta = 10)	1.543	Delta E (theta = 10)	4.262
Delta E (theta = 140)	0.324	Delta E (theta = 140)	0.339
Contrast (theta = 10)	0.031	Contrast (theta = 10)	0.033
Contrast (theta = 140)	-0.011	Contrast (theta = 140)	0.005
<b>Signal Mountain Wilderness Area</b>			
Delta E (theta = 10)	1.032	Delta E (theta = 10)	3.393
Delta E (theta = 140)	0.273	Delta E (theta = 140)	0.146
Contrast (theta = 10)	0.021	Contrast (theta = 10)	0.021
Contrast (theta = 140)	-0.007	Contrast (theta = 140)	0.002

<sup>1</sup> Scattering Angles 10 - referred to as a "forward scatter" where the sun is in front of the observer. This tends to maximize the light scatter.

<sup>2</sup> Scattering Angles 140 - referred to as a "backward scatter" where the sun is in behind the observer. The plume is likely to appear the darkest with this sun angle.

For the second measure of plume perceptibility, total color contrast, the VISCREEN analysis calculated a  $\Delta E$  of 8.266 against terrain at the Hummingbird Wilderness Area, and 2.531 against the sky with the sun toward the observer. There are no screening criteria established for Class II areas.

Cumulative impacts from nearby projects are also not expected to contribute to any visibility impairment at these Class II Wilderness Areas. At the time of this analysis, the nearest project sources were located approximately 25 kilometers to the southeast of the HGP site (near Palo Verde), on the other side of Saddle Mountain. Furthermore, emission trajectories from these other Plants will not align with the HGP emissions in the direction of any nearby Class II Wilderness Area. Based on this geometry and prevailing winds in the area, it is unlikely that visibility in Class II Wilderness Area will be cumulatively affected.

### ***Nitrate and Sulfate Deposition in Class II Areas***

As discussed in the Nitrate and Sulfate Deposition in Class I Areas section, nitrate and sulfate deposition is used as a measure of impact on terrestrial, aquatic, and biological resources. To screen for these potential impacts, the maximum annual NO<sub>x</sub> and SO<sub>2</sub> impacts calculated along



the boundaries of each Class II Wilderness Area closest to HGP were converted to nitrate and sulfate deposition with the procedures described in the Nitrate and Sulfate Deposition in Class I Areas section. The following results were obtained:

**Big Horn Mountains:**

Nitrate:

$$0.2146 \mu\text{g}/\text{m}^3 \times 1.37 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 9.27 \text{ kg/ha-yr}$$

Sulfate:

$$0.045 \mu\text{g}/\text{m}^3 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 1.42 \text{ kg/ha-yr}$$

**Hummingbird Springs:**

Nitrate:

$$0.2025 \mu\text{g}/\text{m}^3 \times 1.37 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 8.75 \text{ kg/ha-yr}$$

Sulfate:

$$0.042 \mu\text{g}/\text{m}^3 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 1.32 \text{ kg/ha-yr}$$

**Eagletail Mountains:**

Nitrate:

$$0.0676 \mu\text{g}/\text{m}^3 \times 1.37 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 2.92 \text{ kg/ha-yr}$$

Sulfate:

$$0.014 \mu\text{g}/\text{m}^3 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 0.44 \text{ kg/ha-yr}$$

**Signal Mountain:**

Nitrate:

$$0.0632 \mu\text{g}/\text{m}^3 \times 1.37 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 2.73 \text{ kg/ha-yr}$$

Sulfate:

$$0.013 \mu\text{g}/\text{m}^3 \times 2 \times 0.05 \text{ m/s} \times (3.1536 \times 10^7 \text{ s/yr}) \times 10^{-5} (\text{kg/ha})/(\mu\text{g}/\text{m}^2) = 0.41 \text{ kg/ha-yr}$$

There are no significance levels applicable to Class II areas, thus these results are being presented for informational purposes only.

## **TOXIC AIR CONTAMINANTS**

Air toxics are compounds for which ambient air quality standards have not been established, but are known or suspected to cause short-term (acute) and/or long-term (chronic or carcinogenic) adverse human health effects. Potential human health effects were screened by comparing predicted maximum short-term and annual ground-level concentrations against Arizona Ambient Air Quality Guidelines (AAAQG). The analysis, described below, resulted in insignificant impacts to the surrounding area.

### **Air Toxic Contaminant Emissions**

The potential emissions of air toxic compounds from the turbines were assessed using two sets of emission factors. The first set of emission factors is for natural gas combustion contained in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Supplement D, the Summary of Results, July 1998 and Supplement F, the Air Toxic Contaminant Emissions section, April 2000 (EPA, 2000). The second is for natural gas-fired turbines contained in the California Air Toxics Emission Factor Database (CATEF), Version 1.2, June 1998, compiled by the California Air



Resources Board. For the purposes of the air toxics screening, the highest emission factor from either set of factors was used in the analysis. The AP-42 emission factor, along with the emission control efficiency that EPA cites for oxidation catalysts, results in a controlled formaldehyde emission factor that is lower than the CATEF emission factor. Given that the HGP proposes to use an oxidation catalyst for CO control, this analysis used the CATEF factor in order to be conservative. There would also be emissions of ammonia due to ammonia slip from the SCR. Ammonia emissions were supplied by the vendor.

Both sets of air toxics emission factors calculate emissions based on the amount of natural gas combusted. Scenario 501G\_4 (100 percent load, 70°F) was used to calculate representative annual and 24-hour average emissions, and Scenario 501G\_7 (100 percent load, 14°F) was used to calculate maximum hourly emissions. Detailed emission data are provided in HGP's PSD and Title V Application materials.

### **Air Toxics Modeling Analysis**

The ISCST3 dispersion modeling parameters used in the air toxics modeling analysis reflected the stack conditions associated with the toxic air contaminants (TAC) emission scenarios (Scenarios 501G\_4 and 501G\_7). Table 12 summarizes the stack parameters associated with these scenarios. Note that for Scenario 501G\_7 (one-hour emissions case), one of the three turbines assumed a lower exit velocity and temperature to account for a potential turbine start-up in the worst-case hour. The modeling was performed using five years of representative meteorological data collected at the Palo Verde Nuclear Generating Facility. Initial modeling was performed for a single pollutant (acetaldehyde) for all averaging periods to identify the receptor locations with maximum concentrations for each averaging time. These receptors would represent the maximum impact locations for all TACs since TAC emissions are directly correlated to fuel use. Therefore, further modeling at these maximum impact locations was performed using a "unit emission rate" (i.e., 1 gram per second (g/s) from each stack). This is sometimes called "Chi-over-Q" (X/Q) modeling, where "Chi" (X) refers to the ground-level concentration and "Q" refers to the emission rate. The X/Q values are then multiplied by the respective emission rates of each TAC (g/s). Emissions used in the modeling analysis are presented in Table 13.

The turbines were grouped based on their operating scenarios. Therefore, the model output was organized in terms of ground-level concentrations ( $\mu\text{g}/\text{m}^3$ ) per turbine group per unit emission rate (g/s). The maximum 1-hour X/Q impact was  $15.627 \mu\text{g}/\text{m}^3$  per g/s. The maximum 24-hour X/Q value was 2.060. The maximum annual X/Q value was 0.177. These X/Q values were multiplied by the estimated TAC emissions (g/s) to calculate the maximum 1-hour, 24-hour, and annual ground-level TAC concentrations, which are presented in Table 14. The maximum annual TAC concentrations occur approximately 7.4 kilometers to the northeast of the HGP location. The maximum 24-hour and 1-hour average TAC concentrations both occurred to the southeast of HGP, located at a distance of 7.4 km and 6.5 km respectively.



### Arizona Ambient Air Quality Guidelines

The modeled air toxic concentrations were compared against AAAQG. The total TAC concentrations are presented in Table 15 along with the AAAQG concentrations. As shown, none of the predicted maximum concentrations of TACs exceed AAAQG concentrations for any averaging time. Thus, by this measure, HGP does not pose a significant human risk to the surrounding area.

### GROWTH IMPACTS

Harquahala Generating Project will not significantly impact growth in the region. It is proposed to serve growth in electrical demand that is projected to occur with or without the project. The plant will be operated by a small workforce of 35 full-time employees. Related commute and truck delivery traffic will constitute a minimal change in existing local and regional traffic. Furthermore, the facility will require minor additional support services.

Table 12: Source Parameters Used For Tac Dispersion Modeling

Source Modeling ID	Easting (x) (m)	Northing (y) (m)	Base Elevation (m)	Stack Height (m)	Stack Gas Temperature (°K)	Stack Gas Exit Velocity (m/s)	Stack Inner Diameter (m)
Annual and 24-Hour Average Modeling							
Scenario 4							
CTG_1S4	303619	3705788	342.9	54.86	354	21.55	5.79
CTG_2S4	303688	3705787	342.9	54.86	354	21.55	5.79
CTG_3S4	303758	3705786	342.9	54.86	354	21.55	5.79
1-Hour Average Modeling							
Scenario 7							
CTG_1S7 <sup>1</sup>	303619	3705788	342.9	54.86	357	16.99	5.79
CTG_2S7	303688	3705787	342.9	54.86	356	23.49	5.79
CTG_3S7	303758	3705786	342.9	54.86	356	23.49	5.79

<sup>1</sup> Represents start-up condition.



Table 13: Harquahala Toxic Air Contaminant Emissions Used In The Modeling Analysis

Pollutant	Annual Emissions-Scenario 4		Daily Emissions-Scenario 4		Hourly Emissions-Scenario 4		Hourly Emissions-Scenario 7	
	Per Turbine	Total (3 Turbines)	Per Turbine	Total (3 Turbines)	Per Turbine	Total (3 Turbines)	Per Turbine	Maximum Total (3 Turbines)
Acetaldehyde	2.11E-02	6.33E-02	2.11E-02	6.33E-02	2.33E-02	6.98E-02	2.33E-02	6.98E-02
Acrolein	7.29E-03	2.19E-02	7.29E-03	2.19E-02	8.04E-03	2.41E-02	8.04E-03	2.41E-02
Ammonia <sup>2</sup>	4.03E+00	1.21E+01	4.03E+00	1.21E+01	4.41E+00	1.32E+01	4.41E+00	1.32E+01
Benz(a)anthracene	6.96E-06	2.08E-05	6.96E-06	2.09E-05	7.67E-06	2.30E-05	7.67E-06	2.30E-05
Benzene	4.19E-03	1.26E-02	4.19E-03	1.26E-02	4.62E-03	1.38E-02	4.62E-03	1.38E-02
Benzo(a)pyrene	4.27E-06	1.28E-05	4.27E-06	1.28E-05	4.71E-06	1.41E-05	4.71E-06	1.41E-05
1,3-Butadiene	1.35E-04	4.05E-04	1.35E-04	4.05E-04	1.49E-04	4.47E-04	1.49E-04	4.47E-04
Dibenzo(a,h)anthracene	7.24E-06	2.17E-05	7.24E-06	2.17E-05	7.99E-06	2.40E-05	7.99E-06	2.40E-05
Dichlorobenzene	3.69E-04	1.11E-03	3.69E-04	1.11E-03	4.07E-04	1.22E-03	4.07E-04	1.22E-03
Ethylbenzene	1.00E-02	3.01E-02	1.00E-02	3.01E-02	1.11E-02	3.32E-02	1.11E-02	3.32E-02
Formaldehyde	3.39E-02	1.02E-01	3.39E-02	1.02E-01	3.73E-02	1.12E-01	3.73E-02	1.12E-01
Hexane <sup>3</sup>	7.97E-02	2.39E-01	7.97E-02	2.39E-01	8.79E-02	2.64E-01	8.79E-02	2.64E-01
Naphthalene	5.11E-04	1.53E-03	5.11E-04	1.53E-03	5.63E-04	1.69E-03	5.63E-04	1.69E-03
Propylene Oxide	1.47E-02	4.41E-02	1.47E-02	4.41E-02	1.62E-02	4.86E-02	1.62E-02	4.86E-02
Toluene	2.19E-02	6.56E-02	2.18E-02	6.55E-02	2.41E-02	7.23E-02	2.41E-02	7.23E-02
Xylenes	2.01E-02	6.03E-02	2.01E-02	6.03E-02	2.22E-02	6.65E-02	2.22E-02	6.65E-02
Arsenic	6.16E-05	1.85E-04	6.15E-05	1.85E-04	6.79E-05	2.04E-04	6.79E-05	2.04E-04
Barium	1.35E-03	4.06E-03	1.35E-03	4.06E-03	1.49E-03	4.48E-03	1.49E-03	4.48E-03
Beryllium	3.69E-06	1.11E-05	3.69E-06	1.11E-05	4.07E-06	1.22E-05	4.07E-06	1.22E-05
Cadmium	3.39E-04	1.02E-03	3.39E-04	1.02E-03	3.73E-04	1.12E-03	3.73E-04	1.12E-03
Chromium	4.31E-04	1.29E-03	4.31E-04	1.29E-03	4.75E-04	1.43E-03	4.75E-04	1.43E-03
Copper	2.62E-04	7.85E-04	2.62E-04	7.85E-04	2.88E-04	8.65E-04	2.88E-04	8.65E-04
Manganese	1.17E-04	3.51E-04	1.17E-04	3.51E-04	1.29E-04	3.87E-04	1.29E-04	3.87E-04
Mercury	8.00E-05	2.40E-04	8.00E-05	2.40E-04	8.82E-05	2.65E-04	8.82E-05	2.65E-04
Molybdenum	3.39E-04	1.02E-03	3.39E-04	1.02E-03	3.73E-04	1.12E-03	3.73E-04	1.12E-03
Nickel	6.46E-04	1.94E-03	6.46E-04	1.94E-03	7.13E-04	2.14E-03	7.13E-04	2.14E-03
Selenium	7.39E-06	2.22E-05	7.39E-06	2.22E-05	8.14E-06	2.44E-05	8.14E-06	2.44E-05
Vanadium	7.08E-04	2.12E-03	7.08E-04	2.12E-03	7.81E-04	2.34E-03	7.81E-04	2.34E-03
Zinc	8.93E-03	2.68E-02	8.92E-03	2.68E-02	9.84E-03	2.95E-02	9.84E-03	2.95E-02



Table 14: Harquahala Toxic Air Contaminant Concentrations

Pollutant	Concentrations - All Turbines ( $\mu\text{g}/\text{m}^3$ )		
	Annual	Daily	Hourly
X/O: (three turbines)	0.17737	2.06017	15.627
Acetaldehyde	3.74E-03	4.35E-02	3.64E-01
Acrolein	1.29E-03	1.50E-02	3.77E-01
Ammonia <sup>2</sup>	7.15E-01	8.31E+00	2.07E+02
Benz(a)anthracene	1.23E-06	1.43E-05	3.60E-04
Benzene	7.42E-04	8.62E-03	2.16E-01
Benzo(a)pyrene	7.58E-07	8.80E-06	2.21E-04
1,3-Butadiene	2.39E-05	2.78E-04	6.98E-03
Dibenzo(a,h)anthracene	1.28E-06	1.49E-05	3.74E-04
Dichlorobenzene	6.55E-05	7.61E-04	1.91E-02
Ethylbenzene	1.78E-03	2.07E-02	5.19E-01
Formaldehyde	6.00E-03	6.97E-02	1.75E+00
Hexane <sup>3</sup>	1.41E-02	1.64E-01	4.12E+00
Naphthalene	9.06E-05	1.05E-03	2.64E-02
Propylene Oxide	2.61E-03	3.03E-02	7.60E-01
Toluene	3.88E-03	4.50E-02	1.13E+00
Xylenes	3.56E-03	4.14E-02	1.04E+00
Arsenic	1.09E-05	1.27E-04	3.18E-03
Barium	2.40E-04	2.79E-03	7.00E-02
Beryllium	6.55E-07	7.61E-06	1.91E-04
Cadmium	6.00E-05	6.97E-04	1.75E-02
Chromium	7.64E-05	8.88E-04	2.23E-02
Copper	4.64E-05	5.39E-04	1.35E-02
Manganese	2.07E-05	2.41E-04	6.05E-03
Mercury	1.42E-05	1.65E-04	4.14E-03
Molybdenum	6.00E-05	6.97E-04	1.75E-02
Nickel	1.15E-04	1.33E-03	3.34E-02
Selenium	1.31E-06	1.52E-05	3.82E-04
Vanadium	1.26E-04	1.46E-03	3.66E-02
Zinc	1.58E-03	1.84E-02	4.61E-01



Table 15: Toxic Air Contaminant Modeling Results

Pollutant	Dispersion Modeling Results ( $\mu\text{g}/\text{m}^3$ )			Arizona Ambient Air Quality Guidelines ( $\mu\text{g}/\text{m}^3$ )			Exceed AAAQGs?		
	Maximum 1-Hour	Maximum 24-Hour	Maximum Annual	1-hour	24-Hour	Annual	1-hour	24-Hour	Annual
Acetaldehyde	3.638E-01	4.349E-02	3.744E-03	6.30E+02	1.70E+02	4.50E-01	NO	NO	NO
Acrolein	3.770E-01	1.503E-02	1.294E-03	6.30E+00	2.00E+00	N/A	NO	NO	NO
Ammonia	2.067E+02	8.307E+00	7.152E-01	2.30E+02	1.40E+02	N/A	NO	NO	NO
Benz(a)anthracene	3.597E-04	1.433E-05	1.234E-06	6.00E+00	1.60E+00	4.80E-03	NO	NO	NO
Benzene	2.164E-01	8.622E-03	7.423E-04	1.70E+02	4.40E+01	1.20E-01	NO	NO	NO
Benzo(a)pyrene	2.208E-04	8.799E-06	7.576E-07	6.70E-01	1.80E-01	4.80E-04	NO	NO	NO
1,3-Butadiene	6.978E-03	2.781E-04	2.394E-05	5.00E+00	1.30E+00	3.60E-03	NO	NO	NO
Dibenzo(a,h)anthracene	3.744E-04	1.492E-05	1.285E-06	6.70E-01	1.80E-01	4.80E-04	NO	NO	NO
Dichlorobenzene	1.909E-02	7.608E-04	6.550E-05	2.00E+02	5.30E+01	1.50E-01	NO	NO	NO
Ethylbenzene	5.186E-01	2.067E-02	1.779E-03	4.50E+03	3.50E+03	N/A	NO	NO	NO
Formaldehyde	1.750E+00	6.974E-02	6.004E-03	2.50E+01	1.60E+01	7.60E-02	NO	NO	NO
Hexane	4.120E+00	1.642E-01	1.414E-02	5.40E+03	1.40E+03	N/A	NO	NO	NO
Naphthalene	2.641E-02	1.052E-03	9.061E-05	6.30E+02	4.00E+02	N/A	NO	NO	NO
Propylene Oxide	7.597E-01	3.027E-02	2.607E-03	3.70E+02	9.80E+01	2.70E-01	NO	NO	NO
Toluene	1.130E+00	4.501E-02	3.875E-03	4.40E+03	3.00E+03	N/A	NO	NO	NO
Xylenes	1.039E+00	4.140E-02	3.564E-03	5.40E+03	3.50E+03	N/A	NO	NO	NO
Arsenic	3.182E-03	1.268E-04	1.092E-05	6.00E-02	1.60E-02	2.00E-04	NO	NO	NO
Barium	7.000E-02	2.790E-03	2.402E-04	1.50E+01	4.00E+00	N/A	NO	NO	NO
Beryllium	1.909E-04	7.608E-06	6.550E-07	6.00E-02	1.60E-02	4.20E-04	NO	NO	NO
Cadmium	1.750E-02	6.974E-04	6.004E-05	7.70E-01	2.00E-01	5.60E-04	NO	NO	NO
Chromium	2.227E-02	8.876E-04	7.642E-05	1.50E+01	4.00E+00	N/A	NO	NO	NO
Copper	1.352E-02	5.389E-04	4.640E-05	3.00E+00	7.90E-01	N/A	NO	NO	NO
Manganese	6.045E-03	2.409E-04	2.074E-05	2.50E+01	7.90E+00	N/A	NO	NO	NO
Mercury	4.136E-03	1.648E-04	1.419E-05	1.50E+00	4.00E-01	N/A	NO	NO	NO
Molybdenum	1.750E-02	6.974E-04	6.004E-05	8.30E+01	4.00E+01	N/A	NO	NO	NO
Nickel	3.341E-02	1.331E-03	1.146E-04	4.50E-01	1.20E-01	2.10E-03	NO	NO	NO
Selenium	3.818E-04	1.522E-05	1.310E-06	6.00E+00	1.60E+00	N/A	NO	NO	NO
Vanadium	3.659E-02	1.458E-03	1.255E-04	1.50E+00	4.00E-01	N/A	NO	NO	NO
Zinc	4.614E-01	1.839E-02	1.583E-03	8.30E+01	4.00E+01	N/A	NO	NO	NO



## EXECUTIVE SUMMARY AND RESULTS OF GROUNDWATER MODELING

To evaluate future groundwater conditions, the 3-dimensional groundwater flow model was used to simulate five different water use scenarios. Based on the results of the five scenarios, HGC's redundant groundwater supply would have more than enough capacity to meet its full consumption requirements, even in the most extreme case of groundwater usage. Under the *Base Case Simulation*, local groundwater withdrawals do not offset the ongoing regional rise of the water table, and the groundwater level rises about 67 feet from its current (1997) depth of about 390 feet to a depth of about 323 feet below land surface by the year 2039. The *Power Plant Simulation* results in a brief decline in the groundwater level; followed by a long-term continued rise in the water table, as groundwater withdrawals are insufficient to offset the ongoing regional groundwater rises. The water table depth is predicted to decline to about 410 feet after 1 year, then rise up to about 377 feet (still above its current level) by the year 2039. The *Residential Development Simulation* also results in a fairly rapid decline in the groundwater level to about 410 feet below land surface, followed by a continued gradual decline in groundwater levels to approximately 425 feet below and surface. However, the overall decline is still only about 35 feet by the year 2039. The *Increased Agriculture Simulation* results in a gradual decline in water levels at the project site by about 78 feet to a depth of approximately 467 feet after 40 years, and the *Extreme Case Simulation* (the worst case simulation that was considered) results in a decline in the groundwater level to about 615 feet below land surface by the year 2039.

Even the extreme case simulation that was modeled suggests a groundwater level decline of only about 225 feet after 40 years of extensive and sustained groundwater withdrawals. The depth of the aquifer beneath the project site is over 1,500 feet, as estimated by regional gravity surveys and confirmed by the drilling of onsite exploratory borings. Thus, even under the extreme case simulation, the aquifer would still have a 900-foot saturated thickness (assuming a conservative total thickness of 1,500 feet), which could sustain the groundwater supply necessary for the HGC power plant, as well as neighboring water users, well beyond the projected 40-year timeframe. Because the actual total thickness of the aquifer is likely far greater, the total saturated thickness would also be greater. Groundwater withdrawal scenarios greater than those modeled would be very unlikely, and would almost certainly result in intervention by regulatory agencies such as ADWR.

Based on the rather extreme scenarios that the groundwater model predicted to be sustainable by Harquahala Valley's groundwater system, an interruption or curtailment of the groundwater supply for the HGC power plant would require an extraordinary increase in groundwater withdrawal. Were this significant increase in groundwater use to occur, the mitigating actions available to the HGC power plant could include deepening of water supply wells or installation of additional wells near the center of the Harquahala Valley, where the depth to bedrock has been estimated to be approximately 8,000 feet (Oppenheimer and Sumner, 1980).



Table 16: Predictive Model Assumptions

PREDICTIVE SIMULATION	MODEL	ASSUMPTIONS			
		Current pumpage (18,000 ac-ft/yr) continues to 2039	1985 pumpage (38,000 ac- ft/yr) from 1999 to 2039	"Anthem" type development (11,760 ac- ft/yr) from 1999 to 2039	3 - Power Plant Wells (total pumpage = 6,000 ac-ft/yr)
1) Base Case Simulation		X			
2) Power Plant Simulation		X			X
3) Residential Development Simulation		X		X	X
4) Increased Agriculture Simulation			X		X
5) Extreme Case Simulation		X	X	X	X

Note: All model simulations are a predictive continuation of historical modeled values, which were calibrated with observed water levels from 1950 to 1997.

Table 17: Predictive Model Results

PREDICTIVE SIMULATION	MODEL	Groundwater Elevation @ 40 Years (feet above mean sea level)	Dept to Water @ 40 Years (feet below land surface)
1) Base Case Simulation		800	323
2) Power Plant Simulation		746	377
3) Residential Development Simulation		697	426
4) Increased Agriculture Simulation		656	467
5) Extreme Case Simulation		508	615

## **ADDITIONAL ENVIRONMENTAL DATA**

Additional copies of modeling studies referenced in items 2 and 3 and additional environmental data are available upon request.

**Attachment 2:**

**5-Year Summary of Benchmark and Scenarios 1 & 2 Air Emission Rates**

## Pollutant Emissions in lbs/MWh

Note: The benchmark summary (annual) is determined from APS baseload, APS fixed contract and APS purchased power (MWh) and actual annual emission factors during the 5-year period.

**Note:** The annual MWh and emission factors are based on APS owned units and actual operations.

Note: The annual MWh are fixed contract purchases from SRP delivered at the Agua Fria plant. The emission factors are based on APS Ocotillo Power Plant (without CTs) from 1998 through 2002.

Note: The emission factors are based on APS Ocotillo Power Plant (with CTs) from 1998 through 2002.

### Scenario 1 Source Totals

## Generation |

### APS Baseload Generation

Note: The APS base load emission rate is 5-year average from 1996 through 2002 for APS owned units (steam, combustion turbine, combined cycle, coal, nuclear).

100

Note: The annual MWh are fixed contract purchases from SRP delivered at the Aqua Fria plant. The emission factor used is based on five year average from 1998 through 2002 for APS Ocotillo Steam Power Plant (without CTs).

## Unit Two

**Note: 1 MWh totals are based on forward market projections (July through December 2003) and purchase contracts.**

<sup>1</sup> Emission factor for PWEC units based on average emission rate from all units

Emission factor provided in Panda Gilla River Track B Bid Proposal

PPL successfully bid a dispatchable product to help meet summer native load requirements however forecasts show no need for this power in 2003.

Wait Time

note: Emission factors for PWEC units based on actual operations from 2001 through 2002 period. Emission factors for other purchased power based on average of all Track B bidders

note: Emission factors for PWEC units based on actual operations from 2001 through 2002 period. Emission factors for other purchased power based on average of all Track B bidders

Scenario 2

003 Projections Including Alternative Purchase Profiles

Scenario 2 Source Totals

Generation Source	lbs	SO2 2003 MWh	lbs/MWh	lbs	NOx 2003 MWh	lbs/MWh	lbs	CO2 2003 MWh	lbs/MWh	lbs	PM10 2003 MWh	lbs/MWh	lbs	CO 2003 MWh	lbs/MWh	lbs	VOC 2003 MWh	lbs/MWh	lbs	Hg 2003 MWh	lbs/MWh
PS Baseload	54,446,560.70	22,223,086.00	2.45	70,638,012.26	22,223,086.00	3.18	28,753,117,590.24	22,223,086.00	1,293.84	4,388,615.02	22,223,086.00	0.20	4,899,523.77	22,223,086.00	0.22	582,248.74	22,223,086.00	0.03	400.02	22,223,086.00	1.80E-05
PS Fixed Contract	14,705.92	800,627.00	0.02	1,232,164.95	800,627.00	1.54	1,128,046,614.16	800,627.00	1,408.95	101,019.91	800,627.00	0.13	349,793.94	800,627.00	0.44	16,973.29	800,627.00	0.02	3.37	800,627.00	4.21E-06
Purchased Power	226,723.63	4,902,141.00	0.05	679,858.34	4,902,141.00	0.14	3,973,500,766.62	4,902,141.00	810.56	191,041.71	4,902,141.00	0.04	473,445.74	4,902,141.00	0.10	74,919.89	4,902,141.00	0.02	12.49	4,902,141.00	2.55E-06
Scenario 2 Totals	54,987,990.25	27,925,854.00	1.98	72,550,035.55	27,925,854.00	2.60	33,854,664,971.01	27,925,854.00	1,212.31	4,680,676.65	27,925,854.00	0.17	5,722,763.45	27,925,854.00	0.20	774,141.92	27,925,854.00	0.03	415.88	27,925,854.00	1.49E-05

IPS Baseload Generation

Unit Type	lbs	SO2 2003 MWh	lbs/MWh	lbs	NOx 2003 MWh	lbs/MWh	lbs	CO2 2003 MWh	lbs/MWh	lbs	PM10 2003 MWh	lbs/MWh	lbs	CO 2003 MWh	lbs/MWh	lbs	VOC 2003 MWh	lbs/MWh	lbs	Hg 2003 MWh	lbs/MWh
steam																					
combined Cycle																					
oil																					
nuclear																					
PS Baseload Totals	54,446,560.70	22,223,086.00	2.45	70,638,012.26	22,223,086.00	3.18	28,753,117,590.24	22,223,086.00	1,293.84	4,388,615.02	22,223,086.00	0.20	4,899,523.77	22,223,086.00	0.22	582,248.74	22,223,086.00	0.03	400.02	22,223,086.00	0.000018

note: The APS baseload emission rate is 5-year average from 1998 through 2002 for APS owned units (steam, combustion turbine, combined cycle, coal, nuclear).

IPS Fixed Contract

Unit Type	lbs	SO2 2003 MWh	lbs/MWh	lbs	NOx 2003 MWh	lbs/MWh	lbs	CO2 2003 MWh	lbs/MWh	lbs	PM10 2003 MWh	lbs/MWh	lbs	CO 2003 MWh	lbs/MWh	lbs	VOC 2003 MWh	lbs/MWh	lbs	Hg 2003 MWh	lbs/MWh
RP Agua Fria	14,705.92	800,627.00	0.02	1,232,164.95	800,627.00	1.54	1,128,046,614.16	800,627.00	1,408.95	101,019.91	800,627.00	0.13	349,793.94	800,627.00	0.44	16,973.29	800,627.00	0.02	3.37	800,627.00	0.000004
Contract Totals	14,705.92	800,627.00	0.02	1,232,164.95	800,627.00	1.54	1,128,046,614.16	800,627.00	1,408.95	101,019.91	800,627.00	0.13	349,793.94	800,627.00	0.44	16,973.29	800,627.00	0.02	3.37	800,627.00	0.000004

note: MWh total based on SRP Agua Fria contract. The emission rate used is based on five-year average from 1998 through 2002 for APS Ocotillo Steam Power Plant without CTs.

Purchased Power

Unit Type	lbs	SO2 January through June 2003 MWh	lbs/MWh	lbs	NOx January through June 2003 MWh	lbs/MWh	lbs	CO2 January through June 2003 MWh	lbs/MWh	lbs	PM10 January through June 2003 MWh	lbs/MWh	lbs	CO January through June 2003 MWh	lbs/MWh	lbs	VOC January through June 2003 MWh	lbs/MWh	lbs	Hg January through June 2003 MWh	lbs/MWh
Market Purchase	216,552.86	2,388,679.00	0.09	477,138.63	2,388,679.00	0.20	1,995,290,741.00	2,388,679.00	838.57	126,201.08	2,388,679.00	0.05	270,537.01	2,388,679.00	0.11	62,086.54	2,388,679.00	0.03	8.12	2,388,679.00	0.000003
WEC																					
Radhawk	8,798.69	2,146,022.00	0.00	148,162.82	2,146,022.00	0.07	1,737,161,888.56	2,146,022.00	809.48	50,646.12	2,146,022.00	0.02	190,352.15	2,146,022.00	0.09	7,940.28	2,146,022.00	0.00	3.80	2,146,022.00	0.000002
West Pk 4	966.52	214,782.00	0.00	44,545.79	214,782.00	0.21	196,981,941.75	214,782.00	917.13	10,814.27	214,782.00	0.05	6,980.42	214,782.00	0.03	3,221.73	214,782.00	0.02	0.46	214,782.00	0.000002
West Pk 5	351.59	81,766.00	0.00	7,457.06	81,766.00	0.09	30,681,873.84	81,766.00	375.24	2,894.52	81,766.00	0.04	2,395.74	81,766.00	0.03	1,185.61	81,766.00	0.01	0.07	81,766.00	0.000001
Saguaro GT 3	53.97	12,551.00	0.00	2,534.05	12,551.00	0.20	10,384,320.87	12,551.00	827.37	485.72	12,551.00	0.04	3,180.42	12,551.00	0.25	485.72	12,551.00	0.04	0.04	12,551.00	0.000003
Renewables	0.00	58,341.00	0.00	0.00	58,341.00	0.00	0.00	58,341.00	0.00	0.00	58,341.00	0.00	0.00	58,341.00	0.00	0.00	58,341.00	0.00	0.00	58,341.00	0.000000
Purchased Total	226,723.63	4,902,141.00	0.05	679,858.34	4,902,141.00	0.14	3,973,500,766.62	4,902,141.00	810.56	191,041.71	4,902,141.00	0.04	473,445.74	4,902,141.00	0.10	74,919.89	4,902,141.00	0.02	12.49	4,902,141.00	0.000003

note: MWh for market purchases are based on purchases recorded between January and June 2003 and general market purchase projections for July through December 2003.

independent PWEC plant purchases were made between January and June 2003. Emission rate used for market purchases is average of Track B bidders.

mission rate used for PWEC plant purchases based on actual operations from 2001 through 2002.

**Attachment 3:**

**5-Year Summary of Benchmark and Scenarios 1 & 2 Water Consumption Rates**

# Benchmark Water Use Summary 1998 through 2002

Benchmark Source Totals	Water Use in Gal/MWh				
	1998	1999	2000	2001	2002
	440	449	429	427	414
	5 Year Average				
	432				

## Benchmark Source Totals

Generation Source	1998		1999		2000		2001		2002	
	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh
APS Baseload	8,814,094,560	21,599,371	9,226,182,221	22,448,037	9,932,494,482	25,048,971	10,636,077,400	25,500,266	9,541,257,215	23,823,940
APS Fixed Contract	318,126,499	370,345	342,223,882	398,398	599,764,108	698,212	398,046,830	463,384	389,840,357	453,830
Purchased Power	1,162,192,028	1,440,730	1,555,810,575	1,919,941	1,096,556,175	1,362,748	1,821,748,750	4,137,541	1,758,183,973	3,980,362
Benchmark Totals	10,294,413,087	23,410,446	11,124,216,678	24,766,376	11,628,814,765	27,109,931	12,855,872,980	30,101,190	11,689,281,544	28,258,133
		440		449		429		427		414

## APS Baseload Generation

Unit Type	1998		1999		2000		2001		2002		Average
	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh	Gal/MWh
Steam	596,516,807	497,639	873,007,812	822,883	1,066,981,299	1,185,176	1,325,278,878	1,482,011	591,328,827	456,582	1296
Combustion Turbine	3,797,554	128,958	4,738,998	143,643	25,319,751	1,447,012	48,863,222	1,387,014	100,848,558	1,467,270	69
Combined Cycle	289,210,570	602,590	373,707,243	757,447	581,360,928	1,067,635	576,180,588	1,131,233	472,493,416	863,081	547
Coal	7,924,569,629	11,564,306	7,974,728,169	11,875,404	8,258,832,504	12,508,403	8,685,754,713	12,573,691	8,376,386,414	12,056,193	695
Nuclear	0	0	0	0	0	0	0	0	0	0	0
	8,805,678	8,805,678	8,848,660	8,848,660	8,840,745	8,840,745	8,926,317	8,926,317	8,960,814	8,960,814	0
APS Baseload Totals	8,814,094,560	21,599,371	9,226,182,221	22,448,037	9,932,494,482	25,048,971	10,636,077,400	25,500,266	9,541,257,215	23,823,940	407

Notes:

- Coal data includes the APS share of NGS consuming a reported 617 gal/MWh prorated to APS fractional ownership.

## APS Fixed Contract

Unit Type	1998		1999		2000		2001		2002	
	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh
SRP Agua Fria	318,126,499	370,345	342,223,882	398,398	599,764,108	698,212	398,046,830	463,384	389,840,357	453,830
Contract Totals	318,126,499	370,345	342,223,882	398,398	599,764,108	698,212	398,046,830	463,384	389,840,357	453,830

Notes:

- Steam plant water consumption is based on 1960s vintage 113 MW plant (APS Ocotillo) five year composite of water consumption (1998-2002) credited 14% for blowdown water reuse.

## Purchased Power

Unit Type	1998		1999		2000		2001		2002	
	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh	Water Use	MWh
Market Purchase	1,162,192,028	1,408,718	1,555,810,575	1,885,831	1,096,556,175	1,329,159	1,821,748,750	4,137,541	1,430,934,524	1,734,466
PWEC										
Redhawk	0	0	0	0	0	0	25,895,387	1,849,671	24,282,525	1,734,466
West Phx 4	0	0	0	0	0	0	269,875,183	404,610	301,816,166	452,498
Saguaro GT 3	0	0	0	0	0	0	0	0	1,150,756	27,399
Renewable Energy	0	32,012	0	34,110	0	33,589	0	31,533	0	31,533
Purchased Total	1,162,192,028	1,440,730	1,555,810,575	1,919,941	1,096,556,175	1,362,748	1,821,748,750	4,137,541	1,758,183,973	3,980,362

Notes:

- Water consumption for Market Purchase power is represented by a composite of water use at the APS Ocotillo Power Plant (including CTs) from 1998 through 2002.

## Scenario 1 2003 Projections Implementing Track B

2003 Water Use in Gal/MWh: 378

### Scenario 1 Source Totals

Generation Source	Water Use	2003 MWh	Gal/MWh
APS Baseload	9,228,613,324	21,992,020	420
APS Fixed Contract	625,015,679	727,608	859
Track B Contracts	229,795,435	2,249,702	102
Purchased Power	289,797,733	2,506,576	116
Scenario 1 Totals	10,373,222,171	27,475,906	378

### APS Baseload Generation

Unit Type	Water Use	2003 MWh	Gal/MWh (1)
Steam	306,205,909	286,191	1070
Combustion Turbine	3,669,242	99,763	37
Combined Cycle	374,619,202	727,517	515
Coal	8,544,118,971	12,555,192	681
Nuclear	0	8,323,358	0
APS Baseload Totals	9,228,613,324	21,992,020	420

Notes:

1. APS baseload water consumption based on an average of water consumption for 1998 through 2002 for each generation type.

### APS Fixed Contract

Unit Type	Water Use	2003 MWh	Gal/MWh
SRP Agua Fria	625,015,679	727,608	859
Contract Totals	625,015,679	727,608	859

Notes:

1. Steam plant water consumption is based on 1960s vintage 113 MW plant (APS Ocotillo) five year composite of water consumption (1998-2002) credited 14% for blowdown water reuse.

### Track B Contracts

Unit Type	July through December 2003		
	Water Use	MWh (1)	Gal/MWh (2)
PWEC	178,135,435	1,997,702	89
Panda Gila River	51,660,000	252,000	205
PPLE (Sundance)	0	0	72
Track B Total	229,795,435	2,249,702	102

Notes:

1. MWh totals are based on forward market model projections and purchase contracts.  
2. Water consumption (gal/MWh) based on values reported by generation source Track B report.

### Purchased Power

Unit Type	January through June 2003		
	Water Use	MWh	Gal/MWh
Market Purchase	88,074,219	450,287	196
PWEC			
Redhawk	20,000,366	1,428,598	14
West Phx 4	59,765,150	89,603	667
West Phx 5	121,169,144	460,719	263
Saguaro GT 3	788,854	18,782	42
Renewables	0	58,587	0
Purchased Total	289,797,733	2,506,576	116

Notes:

## Scenario 2

### 2003 Baseline Projections Including Alternative Purchase Profiles

2003 Water Use in Gal/MWh: 382

#### Scenario 2 Source Totals

Generation Source	Water Use	2003 MWh	Gal/MWh
APS Baseload	9,321,656,411	22,223,086	419
APS Fixed Contract	687,738,708	800,627	859
Purchased Power	662,550,996	4,902,142	135
Scenario 2 Totals	10,671,946,116	27,925,855	382

#### APS Baseload Generation

Unit Type	Water Use	2003 MWh	Gal/MWh
Steam	459,576,760	429,536	1070
Combustion Turbine	7,052,683	191,755	37
Combined Cycle	441,562,280	857,521	515
Coal	8,413,464,689	12,363,201	681
Nuclear	0	8,381,072	0
APS Baseload Totals	9,321,656,411	22,223,086	419

Notes:

1. APS baseload water consumption based on an average of water consumption for 1998 through 2002 for each generation type.

#### APS Fixed Contract

Unit Type	Water Use	2003 MWh	Gal/MWh
SRP Agua Fria	687,738,708	800,627	859
Contract Totals	687,738,708	800,627	859

Notes:

1. Steam plant water consumption is based on 1960s vintage 113 MW plant (APS Ocotillo) five year composite of water consumption (1998-2002) credited 14% for blowdown water reuse.

#### Purchased Power

Unit Type	Water Use	2003 MWh	Gal/MWh
Market Purchase Actual (1)	88,074,219	450,287	196
Market Purchase Projected (2)	467,215,494	2,388,679	196
PWEC (3)			
Redhawk	30,044,308	2,146,022	14
West Phx 4	143,259,594	214,782	667
West Phx 5	21,504,458	81,766	263
Saguaro GT 3	527,142	12,551	42
Renewables	0	58,341	0
Purchased Total	662,550,996	4,902,142	135

Notes:

1. Market Purchases recorded between January and June of 2003.
2. General Market Purchases are projected for July through December 2003.
3. Independent PWEC plant purchases were made between January and June of 2003.